Economics & Forecasts Division

Load Forecasts Report

ontario hydro

February 28, 1991

Dear Sir/Madam:

I am pleased to send you a copy of the latest issue of the annual Load Forecast Report produced by the Economics and Forecasts Division of Ontario Hydro.

Load Forecast Report 901210 contains the Long- and Short-Term Forecasts produced and approved in the calendar year 1990. The goal of the Long-Term Forecast is to provide information for system planning purposes, and as such covers the period to the year 2015. The Short-Term Forecast, on the other hand, is focused on the more immediate future and is used to plan power system operations, revenue requirements, rates and budgets.

Both forecasts give projections of peak and energy demand.

If you have any questions regarding the forecasts or the methodologies and assumptions used, please contact me.

Yours truly,

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LOAD FORECASTS REPORT

NO. 901210

SYSTEM DEMANDS

Load Forecasts Department
Economics and Forecasts Division
Corporate Planning Branch

December 1990

EXECUTIVE SUMMARY

The recommended 1990 Primary Load Forecast for energy is 1.9% and 1.5% lower in the years 2000 and 2015 respectively than the 1989 Primary Load Forecast (LF891211). There is less change in the peak forecast than the energy forecast. For the year 2000, total system energy demand is projected to be 173.9 TW.h, 3.3 TW.h less than last year. By 2015 energy requirements are forecast to be 229.4 TW.h, 3.5 TW.h less than last year. For the years 1989-2000, average annual growth is 2.0%; for 1989-2015 it is 1.9%. Primary December 1-hour Peak is forecast to be 28.9 GW in 2000 and 37.9 GW in 2015. In these years, peak is down 340 MW and 530 MW respectively. However, between 2001 and 2012 Primary peak is almost unchanged from LF891211.

The 1990 Primary Load Forecast is derived by subtracting the projected net impact of Electrical Efficiency Improvement (EEI), Load-Shifting (L-S) and Load Displacement Non-Utility Generation (LD-NUG) programs from the 1990 Basic Load Forecast. By the year 2000, EEI contributes 1950 MW, L-S 1000 MW and LD-NUG 250 MW to reducing Basic Peak Load. This represents 10% of Basic Peak Load in the year 2000 and 37% of the increase in peak from 1989 to 2000. By 2015, the total impact of Hydro's programs is 5400 MW or 12.5% of expected Basic peak load.

Throughout the forecast period, the impact of program-driven Load Displacement Non-Utility Generation (LD-NUG) is down from last year, adding about a half per cent on average to the level of primary demand. (The reduction in demand-side NUG's is more than offset by an increase in supply-side NUG's.) The net load impacts of the Electrical Efficiency Improvement (EEI) and Load-Shifting Programs move in opposite directions in the first part of the forecast and are, in total, almost unchanged until after 2010. Consequently, the small reduction in the 1990 Primary Load Forecast tracks slightly larger changes in the Basic Load Forecast.

The Basic Load Forecast has been influenced by several significant factors which have acted to cancel each other out. Real Ontario GDP is weaker in the near-term as the province experiences a cyclical downturn following the unusually strong growth performance of 1983-88. By the mid-1990's, GDP is expected to return to the levels predicted last year. Between 1995 and 2015, however, higher immigration adds a total of 6.7% to GDP. The impact on load of this increase in economic activity is offset by the 20% real increase in electricity rates which is forecast to occur by 2015. As well, an upgrade to the Ontario Building Code and standards set through the Energy Efficiency Act, are estimated to reduce basic load by about 160 MW in the year 2000. (This load forecast does not attempt to anticipate the impact of unspecified future standards.)

The Basic forecast is determined considering the sectoral forecast produced by a re-specified econometric model and the EPRI end-use models, REEPS, COMMEND and INDEPTH. Both modelling approaches share a common Short-Term Load Forecast for 1990-1995. Numerous modifications to the econometric and end-use forecast methodologies have been made this year. In the residential and industrial sectors, the 1990 econometric and end-use model forecasts are, nonetheless, fairly close to each other and to the 1989 forecast values. In the commercial sector, the divergence between the two methodologies has grown even wider. The econometric forecast is up while better disaggregation in the end-use model and greater likelihood of significant efficiency gains increases confidence in the end-use projection. The recommended Basic energy forecast was set about 5 TW.h above the sum of the end-use model forecasts in 2015. It averages 2.3% growth per annum between 1989 and 2015.

The probability distribution associated with the median forecast is as important as its central tendency. The distribution this year is very similar to last year. The 80% uncertainty band about the median Basic Peak Load Forecast of 32.1 GW in the year 2000 ranges from 27.6 GW to 36.8 GW.

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INTRODUCTION

The Load Forecasts Department normally issues two load forecasts each year: a Long Term Forecast,produced in the fall for system planning purposes; and a Short Term Forecast,produced in early summer for revenue planning,rate development and budget purposes. The Long Term Forecast has a time horizon of approximately 25 years.

This Load Forecast Report contains the Short Term and Long Term Forecasts approved by the Board of Directors on December 10,1990.

In previous years the Load Forecast Report was issued several months into the year following approval by the Board. This was because some information, e.g. the performance of the previous year's forecast over the past year, is not available until then. This resulted,however,in an unfortunate delay in circulating information which was already available. This year,therefore,it was decided that the main text of the report would be issued as soon as possible after approval of the forecast so that users would have access to this information as soon as it became available. At the same time the confidential report on Supplementary report will be circulated early in 1991 which will include an analysis of the performance of LF891211 during 1990. Individual customers' monthly energy for the period 1990-1995 will also be circulated within Ontario Hydro.

The format of the report is changed somewhat from that used in previous years. The Recommended 1990 Load Forecast for the years 1990-2015 is presented first. This was derived taking into account several inputs: the short term forecast,the long term economic outlook and future electricity price levels, estimates from the econometric model (EEMO) and end-use models,the 1989 Load Forecast,judgmental factors,and the forecasts of program-driven Demand Management and Load Displacement Generation.

The Recommended 1990 Load Forecast section includes a comparison of the Primary and Basic Load Forecasts with last year's equivalents,the derivation of the Primary Load Forecast from the Basic Load Forecast,a discussion of the impact of government regulations and standards,a comparison of the 1989 and 1990 forecasts of the Net Load Impact of Program-Driven Demand Management and Load Displacement Non-Utility Generation and a discussion of the selection of the Recommended Primary Load Forecast. A description of the uncertainty band around the recommended forecast completes this section.

The Short Term Load Forecast is presented in chapter 2. It was prepared using the results of:

- A customer survey carried out in the spring (called Regional Estimates);
- The updated economic forecasts based on the latest available trends and anticipated changes in the economic environment;
- Electricity demand forecasting models relying on the most recent data;
- The latest analysis of the deviations of recent Ontario electricity demands from last year's predictions;
- A forecast of the Net Load Impact of Program-Driven Demand Management and Load Displacement Generation.

The Short Term Primary Load Forecast section includes the same kind of Primary/Basic and 1990/1989 comparisons as given in the chapter on the recommended forecast. In addition there is a comparison of the 1990 weather-normal and actual demands and an analysis of the results of the short term forecasting models.

The Long Term Basic Load Forecast is presented in chapters 3 to 5. These sections include a discussion of the long term economic outlook and energy price trends and the results of the econometric and end-use models.

Since 1986, an amount has been subtracted from the Short- and Long-Term Basic Load Forecasts to show the forecasted effects of the net load impact of program-driven Demand Management and Load Displacement Generation on total system demand. The resulting forecast is the Primary Load Forecast. All notation and tables presented in this report refer to the Primary Load Forecast unless the Basic Load Forecast is explicitly noted. The Primary Load Forecast has the same role in the planning process as it always has: it is the most-likely projection of the load Ontario Hydro must plan to supply (after directly controlled loads have been netted out).

The forecast of the Net Load Impact of Program-Driven Demand Management is the estimated net impact on the Basic Load Forecast of programs initiated by Ontario Hydro to alter the level and shape of the load. The Net Impact of Program-Driven Load Displacement Non-utility Generation forecast is the expected reduction in Primary Load due to program-induced additional self-generation of electricity by Ontario Hydro's customers above and beyond that which would otherwise have occured. It is projected that these demand management strategies together will reduce energy demand by 22.4 TW.h in the year 2015,resulting in a Primary Load Forecast of 229.4 TW.h,compared with the Basic level of 251.7 TW.h.

1.0 RECOMMENDED 1990 LOAD FORECAST

1.1 Highlights

The recommended 1990 Primary Load Forecast for energy is 1.9% and 1.5% lower in the years 2000 and 2015 respectively than the 1989 Primary Load Forecast (LF891211). There is less change in the peak forecast than the energy forecast.

The 1990 Primary energy forecast averages 1.9% annual growth from 1989 to 2015, down from 2.0% in the 1989 Load Forecast. Primary peak also grows at 1.9% per year to 2015. Because of the large distortions to load due to extreme weather in December 1989, base year load data has been weather-corrected in the calculation of growth rates and in the tables which follow. This represents a change from past practice and is intended to facilitate growth rate comparisons between forecasts.

Throughout the forecast period, the impact of program-driven Load Displacement Non-Utility Generation (LD-NUG) is down from last year, adding about a half per cent on average to the level of primary demand. (The reduction in demand-side NUGs is more than offset by an increase in supply-side NUGs, which are not part of the load forecast.) The net load impacts of the Electrical Efficiency Improvement (EEI) and Load-shifting (L-S) Programs move in opposite directions in the first part of the forecast and are, in total, almost unchanged until after 2010. Consequently, the small reduction in the 1990 Primary Load Forecast tracks slightly larger changes in the Basic Load Forecast.

The Basic Load Forecast has been influenced by several significant factors which have acted to cancel each other out. Real Ontario GDP is weaker in the near term as the province experiences a cyclical downturn following the unusually strong growth performance of 1983-88. By the mid-1990's, GDP is expected to return to the levels predicted last year. Between 1995 and 2015, however, higher immigration adds a total of 6.7% to GDP. The impact on load of this increase in economic activity is offset by the 20% real increase in electricity rates which is forecast to occur by 2015. As well, an upgrade to the Ontario Building Code and standards set through the Energy Efficiency Act are estimated to reduce basic load by about 160 MW in the year 2000. (This load forecast does not attempt to anticipate the impact of unspecified future standards.)

Numerous modifications to the econometric and end-use forecast methodologies have been made this year. The 1990 econometric and end-use model forecasts are, nonetheless, fairly close to each other and to the 1989 forecast values in the residential and industrial sectors. In the commercial sector, the divergence between the two methodologies has grown even wider. The econometric forecast is up while better disaggregation in the end-use model and greater likelihood of significant efficiency gains increases confidence in the end-use projection. The recommended Basic energy forecast was set about 5 TW.h above the sum of the end-use model forecasts in 2015. It averages 2.3% growth per annum between 1989 and 2015.

Table 1.1: Long-Term Primary Load Forecast - 901210

	December 1-Hour Peak			Annual Energy		
Year	MW	Annual MW	Growth* %	TW.h	Annual TW.h	Growth* %
Short Term						
1989(W/CA)	23368			139.8		
1990	23704	-336	-1.44	141.4	1.7	1.18
1991	23922	218	0.92	143.5	2.1	1.49
1992	24968	1046	4.37	149.4**	5.9	4.11
1993	25525	557	2.23	152.4	3.0	2.01
1994	26097	572	2.24	155.8	3.4	2.23
1995	26889	792	3.03	159.7	3.9	2.50
Long Term						
2000	28872	397	1.43	173.9	2.8	1.72
2005	31612	548	1.83	190.3	3.3	1.82
2010	34710	620	1.89	209.7	3.9	1.96
2015	37927	643	1.79	229.4	3.9	1.81

(W/CA): Weather-Corrected Actual

Average Annual Growth

Period***	MW	%	TW.h	%
1989-1995	587	2.37	3.3	2.25
1989-2000	500	1.94	3.1	2.01
1989-2005	515	1.91	3.2	1.95
1989-2010	540	1.90	3.3	1.95
1989-2015	560	1.88	3.4	1.92

* Values for long term are for five-year period ending in year specified
** Leap Year
*** Using actual 1989 values

1.2 Comparison with Load Forecast 891211 - Primary Energy Demand

The 1990 Primary energy forecast is about 1.2% lower than the 1989 forecast on average. The EEI forecast ramps up faster initially, has a slightly higher load factor in the year 2000 and is 1.8 TW.h higher in the year 2015 than last year. Until 2010, the increased primary load reduction due to EEI is more than offset by a uniform decrease in the LD-NUG forecast of about 1.2 TW.h per year. This makes the difference between the 1990 and 1989 Primary energy forecasts about 0.5 TW.h less than the difference in the two Basic forecasts. (The load displacement NUG decrease is more than compensated for by an increase in sales by NUGs to Hydro which is treated as a supply resource for planning purposes.) In the last five year block, 2010-2015, the gain in EEI is 0.6 TW.h greater than the reduction in LD-NUGs.

The change in the Basic energy forecast is greatest around the year 2000 when demand growth is slowed by price increases and the impact of efficiency standards. Beyond 2000, the faster GDP growth forecast reduces the gap between the 1990 and the 1989 Basic energy forecasts. It is at a minimum around 2010.

Table 1.2: Primary Energy Demand

Year	1990 Recommended Primary Load Forecast (TW.h)	Primary Load Forecast 891211 (TW.h)	Change From 891211 TW.h	Change From 891211 %
Short Term				
1989 (W/CA)	139.8	139.2	0.6	0.40
1990	141.4	142.7	-1.3	-0.91
1991	143.5	146.5	-3.0	-2.05
1992*	149.4	151.5	-2.1	-1.39
1993	152.4	154.7	-2.3	-1.49
1994	155.8	158.3	-2.5	-1.58
1995	159.7	161.5	-1.8	-1.11
Long Term				
2000*	173.9	177.2	-3.3	-1.86
2005	190.3	191.5	-1.2	-0.63
2010	209.7	210.6	-0.9	-0.43
2015	229.4	232.9	-3.5	-1.50
Growth Rates				
1989-2000	2.01	2.22		
1989-2005	1.95	2.01		
1989-2010	1.95	1.99		
1989-2015	1.92	2.00		

(W/CA): Weather-Corrected Actual
* Leap Year

1.3 Comparison with Load Forecast 891211 - Primary Peak Demand

The 1990 peak forecast tends to be reduced less relative to the 1989 peak forecast than the energy forecast. Except for a slower take-up in the yearly years of the projection, the L-S program impact is little changed from last year. The load factor for EEI is slightly higher which accentuates the energy impact for a given peak MW reduction. As well, the 1990 Basic load factor in 1995 is 0.3% lower than in 1989, which raises peak relative to energy. Both load factor differences lead to a higher primary peak result for a given primary energy forecast.

Table 1.3: December 1-Hour Peak

Year	1990 Recommended Primary Load Forecast (MW)	Primary Load Forecast 891211 (MW)	Increase Over 891211 MW	Increase Over 891211 %
Short Term				
1989(W/CA)	23368	23668	-300	-1.27
1990	23704	24155	-451	-1.87
1991	23922	24854	-932	-3.75
1992	24968	25517	-549	-2.15
1993	25525	26031	-506	-1.94
1994	26097	26550	-453	-1.71
1995	26889	26979	-90	-0.33
Long Term				
2000	28872	29214	-342	-1.17
2005	31512	31545	-33	-0.10
2010	34710	34709	1	0.00
2015	37927	38452	-525	-1.37
Growth Rates				
1989-2000	1.94	1.93		
1989-2005	1.89	1.81		
1989-2010	1.90	1.84		
1989-2015	1.88	1.88		

(W/CA): Weather-Corrected Actual

1.4 Comparison of Primary to Basic Load Forecast

The Basic Load Forecast takes into account all the factors affecting the future demand for electric power and energy except those activities which Hydro may undertake in future to influence the amount and timing of electricity demands on Ontario Hydro. As such, it includes the impact of government regulations and standards concerning energy use. The Primary Load Forecast remains the forecast of the electric power and energy which Ontario Hydro must generate or purchase to meet the electricity demand of its customers in Ontario. It is derived by subtracting the expected future net impact of Electrical Efficiency Improvement (EEI), Load Shifting (L-S) and Load Displacement Non-Utility Generation (LD-NUGs) from the Basic Load Forecast. The net impact on load of these programs may be due to direct financial incentives or other means by which Ontario Hydro incurs costs to provide a targeted benefit to customers (e.g. customized information such as energy audits).

The net load impact of Hydro's programs is expected to reduce peak power requirements in the year 2000 by 10.0%. Their 3.2 GW contribution by the year 2000 represents about 40% of the 9.7 GW increase in peak demand forecasted between 1990 and 2000. The corresponding figures for energy are lower as L-S programs are currently assumed to have no energy impact. As noted previously the LD-NUG forecast is lower due to a preference by NUGs to sell to Hydro rather to displace their own load directly. The forecasted net load impact of EEI, L-S and LD-NUG programs is described in Section 6.

Table 1.4: 1990 Load Forecast - Primary vs Basic

	December Peak - MW				Energy - GW.h			
Year	Basic	Impact of Incentives	Primary	% Diff.	Basic	Impact of Incentives	Primary	% Diff.
Short Term								
1989(W/CA)	23524	156	23368	0.7	139889	132	139758	0.1
1990	24057	353	23704	1.5	142411	984	141423	0.7
1991	24483	561	23922	2.3	145330	1812	143516	1.2
1992	25765	797	24968	3.1	152160	2724	149436	1.8
1993	26577	1052	25525	4.0	156137	3720	152415	2.4
1994	27400	1303	26097	4.8	160446	4657	155790	2.9
1995	28442	1553	26889	5.5	165281	5538	159745	3.4
Long Term								
2000	32068	3195	28873	10.0	186330	12454	173876	6.7
2005	35668	4155	31513	11.6	207248	16970	190278	8.2
2010	39507	4797	34710	12.1	229555	19853	209702	8.6
2015	43320	5393	37927	12.4	251714	22361	229353	8.9
Growth Rates								
1989-1995	3.2		2.4		2.8		2.3	
1989-2000	2.9		1.9		2.6		2.0	
1989-2010	2.5		1.9		2.4		2.0	
1989-2015	2.4		1.9		2.3		1.9	
1990-2000	2.9		2.0		2.7		2.1	
2000-2015	2.0		1.8		2.0		1.9	

(W/CA): Weather-Corrected Actual

1.4.1 The Impact of Government Regulations and Standards

The Government of Ontario's Energy Efficiency Act enables it to declare minimum standards for energy efficiency for a wide variety of equipment sold in the province. This is the first load forecast that explicitly takes into account standards that either have already been declared or are expected to be declared shortly. The appliances affected and the estimated impact of the standard set are summarized in Section 4.1 and discussed in more detail in the '1990 Residential Sector End-Use Load Forecast Report'. Because the standards currently pertain largely to household appliances or heating and cooling equipment, their impact is almost entirely felt in the residential sector and the apartment building segment of the commercial sector.

The province is also about to upgrade the energy efficiency elements of the Ontario Building Code. This impact is also quantified in Section 4.1.

The introduction of new standards and the revision of the Ontario Building Code accelerate the efficiency gains otherwise built into the Basic load forecast. The end-use models were used to estimate the extent of the change. The results in terms of reduction in peak MW by sector are summarized in Table 1.4.1.

The higher efficiency levels in the Basic Load Forecast come about due to faster take-up of a portion of the conservation measures that contribute to the EEI forecast. The impact of these regulations has been considered on an end-use basis; the estimates are shown in Table 6.2.3.1 and are summarized below in Table 1.4.1. The EEI forecast is reduced by the amounts shown and so diminishes the net impact of the regulations on the Primary Load Forecast.

Table 1.4.1: **The Impact of Standards on Efficiency Improvement - Net Reduction in Peak Load**

(MW)

	Basic			EEI	Primary
	Residential	Commercial	Total	Total	Total
1995	71	17	88	14	74
2000	165	50	215	53	162
2005	196	77	273	80	193
2010	245	95	340	97	243
2015	239	96	335	115	220

1.5 Comparison of Basic Load Forecast 901210 with Basic Load Forecast 891211

As noted in Section 1.2, the change in the Primary energy forecast closely parallels the change in the Basic (with the exception of the last five years of the forecast). The reduction in the 1990 Basic relative to the 1989 Basic is also about 1.2%.

The small net change belies the influence of several significant differences in input factors whose impacts turn out to be nearly offsetting. By 1991, Ontario GDP is down nearly 3% from last year. It recovers to within 1% by 1995, is up 0.6% by 2000 and up 6.7% by 2015. Beyond 1995, the faster pace for GDP growth is attributable to an upward revision in the immigration forecast which boosts labour force growth by 0.4% per year. Other things equal, in the long-run these GDP changes would flow through into load growth nearly proportionately, increasing it about 6%-7%.

The real price of electricity is forecast to increase about 10% in the first five years of the forecast, is stable for 10 years and then goes up a further 10% between 2005 and 2015. Last year's load forecast assumed constant real prices. The long-run own-price elasticity in EEMO would suggest that this price change would eventually reduce load about 8%. Neither the full GDP nor the full price impact would have occurred by 2015.

The introduction of standards reduces basic load levels about 0.5% between the years 2000 and 2015.

In addition, both the econometric and the end-use model have been modified significantly. Many of the changes in methodology and input data are summarized in Sections 4 and 5. Further details are provided in the background reports which accompany this forecast.

Table 1.5: Basic Load Forecast Comparison

	December One-Hour Peak - GW				Energy - TW.h			
Year	Load Forecast 891211	Load Forecast 901210	Difference GW	Difference %	Load Forecast 891211	Load Forecast 901210	Difference TW.h	Difference %
Short Term	23.82	23.37*	-0.45	-1.9	139.33	139.76*	0.43	0.3
1989	24.50	24.06	-0.44	-1.8	143.78	142.41	-1.37	-1.0
1990	25.44	24.48	-0.96	-3.8	148.46	145.33	-3.13	-2.1
1991	26.41	25.77	-0.64	-2.4	154.52	152.16	-2.36	-1.5
1992	27.24	26.58	-0.66	-2.4	158.88	156.14	-2.74	-1.7
1993	28.04	27.40	-0.64	-2.3	163.36	160.45	-2.91	-1.8
1994	28.76	28.44	-0.32	-1.1	167.59	165.28	-2.31	-1.4
1995								
Long Term	32.62	32.07	0.55	-1.7	190.05	186.33	-3.72	-2.0
2000	35.96	35.67	-0.29	-0.8	209.54	207.25	-2.29	-1.1
2005	39.61	39.51	-0.10	-0.3	230.82	229.56	-1.26	-0.5
2010	43.69	43.32	-0.37	-0.8	254.58	251.71	-2.87	-1.1
2015								
Growth Rates								
1989-1995	3.2	3.3			3.1	2.8		
1989-2000	2.9	2.9			2.9	2.6		
1989-2015	2.4	2.4			2.3	2.3		
1990-2000	2.9	2.9			2.8	2.7		
2000-2015	2.0	2.0			2.0	2.0		

* Weather-Corrected Actual

1.6 Comparison of Net Load Impacts of Demand Management and Load Displacement Programs, LF901210 versus LF891211

The forecast of the net load impact of EEI programs gives more credit to activities in the short term which advance conservation measures several years, but may not have a long-term impact. Such programs add about 100 MW to the load reduction due to EEI in 1995 without altering the year 2000 result.

It is still considered that the achievement of the year 2000 Corporate target is a reasonable forecast assuming significantly higher incentive levels will be forthcoming within 2-3 years. Wider and more stringent application of government regulation and standards may displace the need for some EEI programs. The year 2000 forecast of about 1950 MW takes into account the overlap between the current set of standards and the EEI programs which were intended to deliver 2000 MW. Should the role of standards increase significantly, it may be expected that the contribution of corporate EEI programs will diminish further.

The potential for induced EEI is about 1000 MW higher in the year 2000 than last year due to the inclusion of technologies that at the time were either not considered proven and reliable or were not economic. Penetration rates are now estimated to be lower in the commercial sector and higher in the residential sector, with the result that identified attainable EEI by the year 2000 is about 2000 MW, up 280 MW from 1989. By 2015, the EEI impact is 280 MW higher than in LF891211.

Response to time-of-use rates to date is somewhat weaker than anticipated. The forecast for the next few years is down from last year; by 1995 the load-shifting program is expected to contribute 120 MW less than in the 1989 forecast. Thereafter, the forecast is almost the same as last year. If recent response trends continue, the Corporation may have to rely more heavily on incentive programs to influence customers directly.

The net load impact of load displacement NUGs has been reduced 185 MW in 2000 and nearly 300 MW in 2015. At the same time, the total program-driven contribution of NUGs to Ontario's electricity supply/demand balance in the year 2000 has been raised to 1850 MW. The shift to purchased NUGs from load displacement represents a customer preference.

The total net effect of changes in the EEI, L-S and LD-NUG forecasts for 1990 is to cut program-driven load impacts by about 230 MW in 1995, 210 MW in 2000 and 110 MW in 2010 relative to the 1989 projection. There is a 160 MW increase by 2015. The lower level of demand-side programs throughout most of the forecast period acts to raise the Primary Load Forecast. The change is, however, more apparent than real, as it largely relates to the re-allocation of NUGs from the demand-side to the supply-side.

Table 1.6: **Comparison of Cumulative Load Impact of Incentive-Drive Management and Load Displacement, LF()1210 vs LF891211 (December Peak MW)**

	LF901210			LF891211	
Year	L-S/ EEI*	LD**	Total	Total	Difference in Total
Short Term					
1990	286	67	353	343	10
1991	491	70	561	583	-22
1992	708	89	797	888	-91
1993	935	117	1052	1211	-159
1994	1170	133	1303	1485	-182
1995	1415	138	1553	1782	-229
Long Term					
1996	1691	159	1850	2111	-261
2000	2947	248	3195	3402	-207
2005	3890	265	4155	4416	-361
2010	4518	279	4797	4904	-107
2015	5100	293	5393	5238	155

* Load Shifting (Time-of-Use Rates) and Electrical Efficiency Improvement Programs

** Load Displacement Non-Utility Generation

1.7 Selection of Recommended Primary Load Forecast

The recommended Primary Load Forecast is derived by subtracting the forecast of the net load impact of program-driven demand management and load displacement generation from the recommended Basic Load Forecast. The latter is determined considering as input the long-term load forecasts produced by the Econometric Energy Model of Ontario (EEMO) and the end-use models. Both are spliced into the Short-Term Load Forecast for 1990-1995.

The recommended total system Basic Load Forecast was determined sector by sector. In the residential sector, the EEMO and end-use (REEPS) forecasts are almost identical to each other in the year 2000 and to last year. Beyond the year 2000, the end-use forecast growth rate slows so that by 2015, it is 10% lower than the EEMO forecast. The EEMO result is about 5% higher than last year by 2015, while REEPS is about the same as in 1989. The end-use forecast was selected for the residential sector.

There is little change in the industrial sector forecasts in aggregate. Both model forecasts are a little lower than last year, with the end-use ('INDEPTH') about 5% lower than EEMO. The end-use model this year has emphasized load changes due to recycling and enhanced environmental concerns which would not be picked up econometrically, and so was selected to provide the Basic Load forecast for the industrial sector.

The gap between the econometric and end-use model forecasts for the commercial sector is even wider than last year, about 25 TW.h or about 25% in 2015. The EEMO forecast is the result of a thorough attempt to improve the quality of the statistical results in the face of poor data yet ends up about 10% higher than in the 1989 forecast. The end-use forecast ('COMMEND') is almost unchanged in total. With further disaggregation of the end-uses in COMMEND and the rapid advances in technologies which increase the efficiency of electricity use in the commercial sector, it does not seem reasonable to split the difference between these divergent forecasts, as was done last year. The recommended commercial sector forecast was set 5 TW.h above the COMMEND solution in 2015.

The sectoral forecasts for both the end-use and econometric models are presented in Section 4 and 5 respectively. Table 1.7 provides the result obtained when the selected forecasts for each sector are used to derive the recommended Basic Load Forecast.

Table 1.7: Summary of Forecasts

	Ontario Hydro Basic Energy Demand Model Comparison (TW.h)		Official Load Forecast 901210 (TW.h)			
Year	EEMO**	End-Use**	Basic	Impact of EEI	Load Displacement	Primary
1989*	140.9	140.9	140.9	0.0	0.1	140.8
1990	141.2	141.4	142.4	0.6	0.4	141.4
1995	165.2	165.3	165.3	4.5	1.0	159.7
2000	192.3	184.3	186.3	10.6	1.8	173.9
2005	221.5	204.2	207.2	15.0	2.0	190.3
2010	252.2	225.4	229.6	17.8	2.1	209.7
2015	284.6	246.3	251.7	20.2	2.2	229.4
Growth Rates***						
1989-2000	2.9	2.5	2.6			1.9
1989-2005	2.9	2.3	2.4			1.9
1989-2010	2.8	2.3	2.4			1.9
1989-2015	2.7	2.2	2.3			1.9

* Actual
** The End-Use Model and Econometric Energy Model of Ontario Forecasts are described in Sections 4 and 5 respectively.
*** Average annual percent change

1.8 Load Forecast Uncertainty

The methodology used to prepare the probability distribution associated with the 1990 load forecast is the same as the one used last year. The equation relating GDP to load in a manner such that the electricity intensity of the economy varies through the forecast period has been further improved. It now tracks the recommended Basic load forecast within 1% over the forecast horizon. Its better statistical fit to history tends to narrow the uncertainty band when the coefficient and residual standard errors are simulated in conjunction with the distribution on GDP. The increase in the forecast population growth rate has the effect of widening the GDP distribution. The resulting probability distribution is very similar to the one produced for LF891211, slightly wider and with a little less skew on the high side.

Table 1.8: Uncertainty Band for Annual Basic Energy (TW.h)

Year	Lower (10%)	Forecast (50%)	Upper (90%)
Short Term			
1989 (Actual)		140.9	
1990	139.2	142.4	145.9
1991	139.4	145.3	151.4
1992	142.4	151.7	161.3
1993	143.8	156.1	167.7
1994	145.5	160.4	176.4
1995	149.9	165.3	183.1
Long Term			
2000	160.3	186.3	213.8
2005	165.2	207.2	252.6
2010	188.3	229.6	279.4
2015	213.8	251.7	293.9
Growth Rates			
1989 - 1995	1.1	2.7	4.5
1989 - 2000	1.2	2.6	3.9
1989 - 2005	1.0	2.4	3.7
1989 - 2010	1.4	2.4	3.3
1989 - 2015	1.6	2.3	2.9

Analysis of the most appropriate methodology to be used for the probability distribution for the Basic Peak Load Forecast is not complete. In the interim, a peak distribution derived using a constant load factor applied to the energy distribution is considered satisfactory. In the year 2000, the 80% confidence band ranges from 27.6 GW to 36.8 GW, or about 9 GW wide. By 2015, the range is from 36.8 GW to 50.6 GW, about 14 GW.

Simulation studies have been undertaken to investigate the sensitivity of the primary load forecast bandwidth to various parameters which influence the net impact of demand management programs. There is insufficient experience with Hydro's programs to prepare a definitive estimate at this time. Where a Primary Load Forecast probability distribution is required, it is recommended that the absolute deviations from the median in the Basic distribution be applied.

Given the sources of external uncertainty, in addition to the uncertainty attached to the load forecasting process itself, the necessity for care in the use of the load forecast cannot be overstressed. The load forecast cannot be used as only a a single line projection; the sources and consequent ranges of forecast error must be considered as well.

For this reason, the probability distribution associated with the median forecast is as important as its central tendency.

2.0 THE SHORT-TERM LOAD FORECAST - 1990 TO 1995

2.1 Highlights

The 1990 Short-Term Load Forecast is lower than the December 1989 (LF891211) forecast in all forecast years. The average annual rate of growth for primary energy between 1990 and 1995 is still 2.5%, however the level of weather-normal primary energy demand starts the period down 0.9% and ends it 1.1% down from last year's forecast. The average level is 1.4% down for all years, with the greatest change in 1991 when it is 2% less than LF891211.

In terms of actual energy demand, 1989 was affected by severe weather which added 0.7% to the year and the underlying demand was an additional 0.5% more than forecast. The year-over-year growth for 1990 in actual demand unadjusted for actual weather is forecast to be about -0.5%, since the first half of 1990 has seen very moderate weather which has reduced actual consumption by about 1.3 TW.h below the weather normal value. This represents about 0.9% of forecast energy for the year. On a fully weather normal-basis, the 1990 growth is forecast to be 1.2% above weather normal 1989 energy.

The Primary Load Forecast is derived from the Basic Load Forecast by subtracting the estimated net impact on load of program-driven efficiency improvement, load shifting (largely time-of-use rates) and load displacement non-utility generation. The Basic Load Forecast was prepared in July for rate finalization purposes considering all the following information: the 1990 Customer Estimates (completed individually in April and May and compiled in early July); the results of econometric annual models with data to the end of 1989; the results of the monthly models especially the State-Space model using weather corrected load data to June 1990; and various end-use analyses.

The Basic Load Forecast underlying the Primary grows at an average rate of 3.0% annually for energy. This is about 0.2% less than last year's forecast. The reduction in growth rates foreseen for 1990 and 1991 to an average of 1.6% for the two years is driven by the slowdown in Ontario GDP growth and the collapse of the construction boom of 1987-89, together with the tapering off of new capital investment in plant and equipment in the manufacturing sector. The weakness in the economy in the second quarter has strongly influenced the Load Forecast and so the Basic load growth rate is now lower for the first two years than it has been since 1982. A cyclical downturn following the unsustainably high growth of the past 5 years is now clearly in evidence. By the end of the short-term forecast, GDP returns to the long-term trend value projected last year. However, there is an electricity price effect which depresses load as prices are projected to be about 10% higher in real terms by 1995 than they are in 1990.

Hydro's demand management programs have a substantial downward impact on load growth. For the first three years of the forecast, the energy impact of the Electrical Efficiency Improvement Program is nearly double that shown last year and ends up in 1995 at about 4.5 TW.h annually, up 1 TW.h.

The estimated contribution of the Load Shifting program, including Time-of-Use Rates, has been revised down about 18% on average for the first four years. The Load Displacement Non-Utility Generation Program impact is less than half that projected last year. The latter reduction is due to a major shift by the applicant generators toward sales to Hydro through a third party and away from simple displacement of their own load. The net impact of all these changes in demand management programs for 1995 is a reduction in December peak of 229 MW and a reduction in annual energy of 0.55 TW.h for 1995, both relative to last year's forecasted contributions.

2.2 The Short-Term Primary Load Forecast

The 1990 Short-Term Primary Load Forecast for the total system is summarized in Table 2.2.1:

Table 2.2.1: Total System Primary Demand

	December 1-Hour Peak			Energy					
		Annual Growth				Annual Growth			
Year	MW	MW	%	Avg MW	TW.h	Avg MW	%	TW.h	%
Short Term									
1989	24377*			16070	140.8				
1990	23704	-673	-2.8	16144	141.4	74	.5	.6	.5
1991	23922	218	.9	16383	143.5	239	1.5	2.1	1.5
1992	24968	1046	4.4	17012	149.4	629	3.8	5.9	4.1
1993	25525	557	2.2	17399	152.4	387	2.3	3.0	2.0
1994	26097	572	2.2	17784	155.8	385	2.2	3.4	2.2
1995	26889	792	3.0	18236	159.7	451	2.5	4.0	2.5
Avg Increase									
1989-95		419	1.6			361	2.1	3.2	2.1
1990-95		637	2.6			418	2.5	3.7	2.5

* Actual Peak Demand (including relief)

The above table shows the forecast year's weather normal energy, with actual for the first six months and forecast for the remainder of 1990. The 1989 values are actual unadjusted for weather. The actual weather effect of the first six montns is unusually large this year, so this table is supplemented by tables 2.2.1(A) and (B) which clarify the strong effects of the weather on load for this year and for 1989. Table 2.2.1(B) shows 1990 with the actual energy sales as affected by the unusual winter weather together with the forecast (always weather normal). This is the 1990 forecast for planning purposes. Table 2.2.1(A) is intended to permit a view of the growth rates net of the weather effects of 1989 and 1990, and shows all figures corrected for abnormal weather.

Table 2.2.1(A): **Total System Primary Demand**
All figures Weather-Normal

	December 1-Hour Peak			Energy					
	Forecast December Peak	Annual Growth		Forecast		Annual Growth			
Year	MW	MW	%	Avg MW	TW.h	Avg MW	%	TW.h	%
1989*	23368			15954	139.8	686	4.5	5.7	4.2
1990	23704	336	1.4	16144**	141.4	190	1.2	1.6	1.2
1991	23922	218	.9	16383	143.5	239	1.5	2.1	1.5

* Weather-Corrected Actual
** Weather-Corrected to July, forecast after that to year end is weather-normal.

Table 2.2.1(B): **Total System Primary Demand**
All figures Actual Demand

	December 1-Hour Peak			Energy					
	Forecast December Peak	Annual Growth		Forecast		Annual Growth			
Year	MW	MW	%	Avg MW	TW.h	Avg MW	%	TW.h	%
1989*	24377	1444	6.3	16070*	140.8	770	5.0	6.4	4.7
1990	23704	-673	-2.8	15985**	140.0	-85	-.5	-.7	-.5
1991	23922	218	.9	16383	143.5	398	2.5	3.5	2.5

* Actual
** Actual with effect of weather to June, forecast after that to year end is weather-normal.

2.3 Comparisons

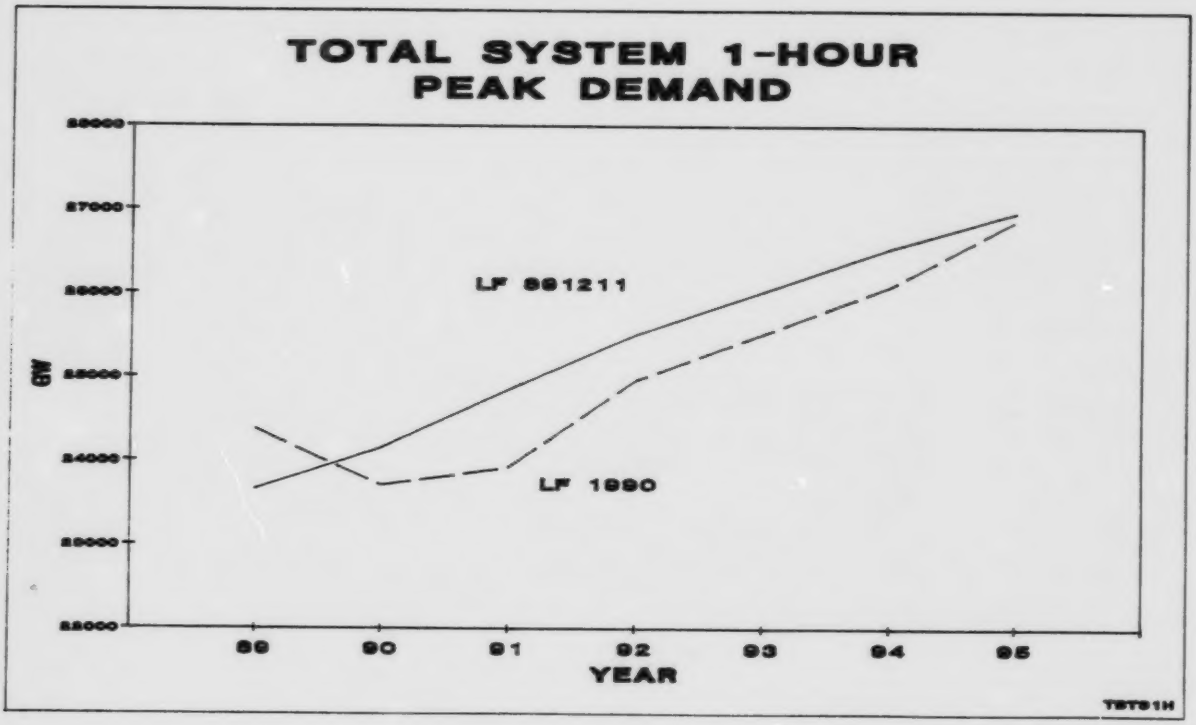
2.3.1 Comparison with Load Forecast 891211 - Peak Demand

The level of the primary peak forecast in 1995 is -.3% or 90 MW lower than projected last year.

Table 2.3.1: 1-Hour Peak Demand

Year	Annual Growth		Primary Load Forecast 891211		Change from Primary Load Forecast 891211	
	MW	%	MW	%	MW	%
1989*	24377		23668			
1990	23704	-2.8	24155	2.1	-451	-1.9
1991	23922	.9	24854	2.9	-932	-3.7
1992	24968	4.4	25517	2.7	-549	-2.2
1993	25525	2.2	26031	2.0	-506	-1.9
1994	26097	2.2	26550	2.0	-453	-1.7
1995	26889	3.0	26979	1.6	-90	-.3
Avg. Increase						
1989-95		1.6			-497	-2.0
1990-95		2.6			-506	-2.0

* Actual



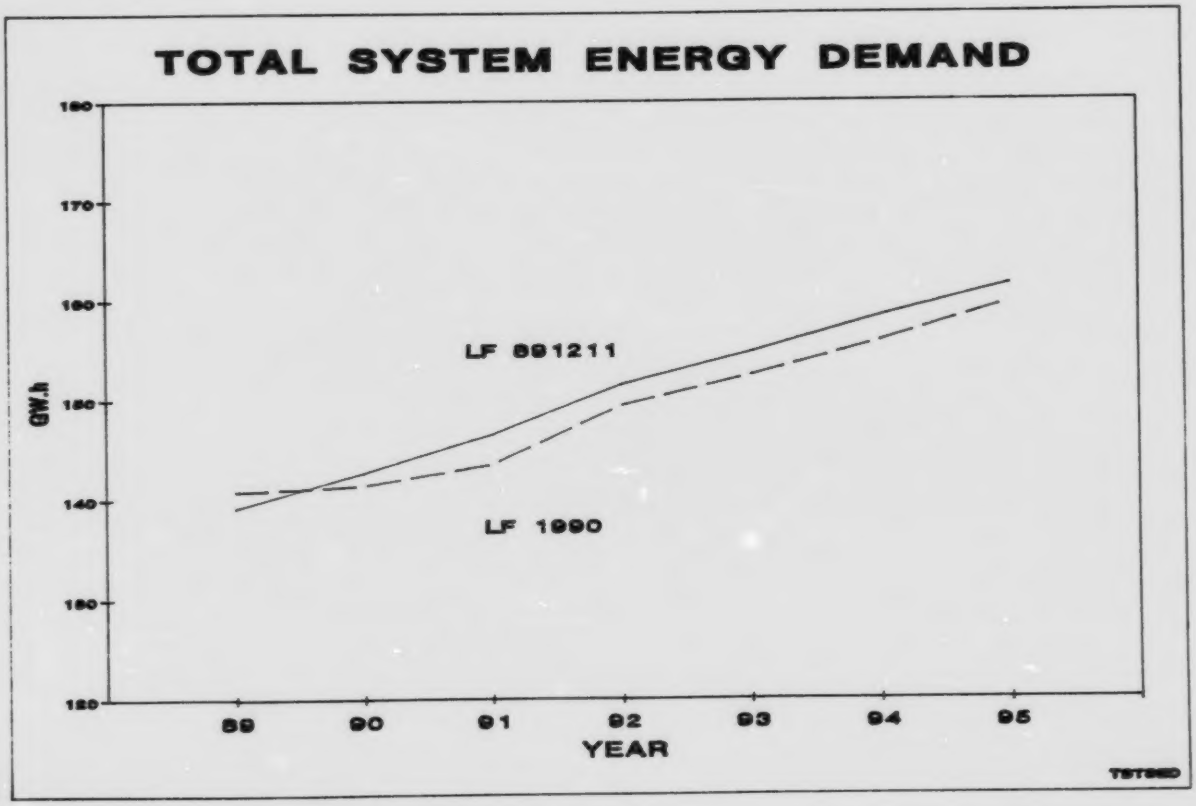
2.3.2 Comparison with Load Forecast 891211 - Energy Demand

The level of the energy forecast is approximately 1.0% lower on average than the 1989 Short-Term Forecast for the period 1990 to 1994.

Table 2.3.2: Energy Demand

	1990 Primary Load Forecast			Primary Load Forecast 891211			Change from Primary Load Forecast 891211	
Year	Avg MW	TW.h	% Inc TW.h	Avg MW	TW.h	% Inc TW.h	TW.h	%
1989*	16070	140.8		15889	139.2		1.6	1.1
1990	16144	141.4	.5	16294	142.7	2.6	-1.3	-.9
1991	16383	143.5	1.5	16720	146.5	2.6	-3.0	-2.0
1992	17012	149.4	4.1	17248	151.5	3.4	-2.1	-1.4
1993	17399	152.4	2.0	17665	154.8	2.1	-2.3	-1.5
1994	17784	155.8	2.2	18071	158.3	2.3	-2.5	-1.6
1995	18236	159.7	2.5	18435	161.5	2.0	-1.7	-1.1
Avg. Increase								
1989-95			2.1			2.5	-1.6	-1.0
1990-95			2.5			2.5	-2.2	-1.4

* Actual



2.3.3 Derivation of the Primary Load Forecast from the Basic Load Forecast

The Basic Load Forecast is the forecast of the demand for electricity (at the generator) without taking into account the net impact of Hydro's incentive-driven programs to influence the level and timing of electricity demands on Ontario Hydro. The Basic Load Forecast does take into account energy efficiency improvements and load displacement non-utility generation that are driven by normal market forces. The Primary Load Forecast is the forecast of power and energy which Ontario Hydro generates or purchases in order to meet the demands of its customers in Ontario. It incorporates the net impact of demand management and program-driven load displacement non-utility generation programs.

Electrical generation that is not owned or operated by Ontario Hydro and that is consumed by the generating customer reduces the demand on Ontario Hydro's system. It is known as load displacement non-utility generation (LD-NUG). Nearly all industrial cogeneration currently in operation in Ontario falls into this category. Due to Hydro's programs, it is anticipated a further 138 MW dependable will be installed by 1995. The LD-NUG estimates are lower than last year to the Short-Term Forecast horizon since participants have opted to become suppliers of generation to Ontario Hydro rather than becoming load displacement generators. Generation is considered a supply resource for planning purposes, and does not impact on the Load Forecast.

The net load impact of Hydro's programs to improve electrical efficiency in Ontario ramps up much more rapidly in this forecast than last year's. The Energy Management Branch is accelerating the rate it plans to introduce programs and is broadening their scope as well. Programs providing financial incentives and valuable customized information will be available in all sectors that use electricity, to motivate efficiency gains that would not otherwise be expected to take place. An outline of these electrical efficiency improvement (EEI) programs is contained in the Energy Management Branch Business Plan. The net impact estimates presented here are based on an assessment of the projections contained in this plan made by the Economics and Forecasts Division in consultation with the Energy Management Branch. The cumulative impact of EEI by 1994 is now expected to be 722 MW, up from 577 MW in the 1989 Load Forecast.

The forecasted impact of the load-shifting (L-S) programs by 1994 has been reduced from 575 MW in LF891211 to 448 MW in this forecast.

Table 2.3.3 shows the Basic Load Forecast for peak and energy. It also summarizes the annual net impacts of EEI, L-S and LD-NUG. The Primary Load Forecast is derived by subtracting the net program impacts from the Basic Load Forecast. Basic energy is projected to grow at an average annual rate of 3.0% between 1990 and 1995; Basic peak grows at 3.4%.

It is the Basic Load Forecast that may be forecasted using statistical models built on past load data. In future, to maintain consistency in the historical data set as demand management impacts contribute to reducing the measured primary load, basic load will need to be estimated by adding the estimated net program impacts to the observed and recorded primary load data. This will facilitate the modelling of the Basic load without the effects of intervention.

Table 2.3.3: 1990 Short-Term Forecast - Derivation of Primary from Basic

December Peak - MW

Year	Basic	Annual Growth MW	%	EEI	L-S	LD-NUG	Primary
1989*	23524	591	2.6	36	62	58	23368
1990	24057	533	2.3	147	139	67	23704
1991	24483	426	1.8	277	214	70	23922
1992	25765	1282	5.2	419	289	89	24968
1993	26577	812	3.2	568	367	117	25525
1994	27400	823	3.1	722	448	133	26097
1995	28442	1042	3.8	883	532	138	26889
Avg % Inc							
1989-1995		816	3.2				2.4
1990-1995		877	3.4				2.6

Energy - GW.h

Year	Basic	Annual Growth GW.h	%	EEI	L-S	LD-NUG	Primary
1989*	139889	5494	4.1	53	0	79	139758
1990	142411	2521	1.8	581	0	406	141423
1991	145330	2919	2.0	1295	0	519	143516
1992	152160	6830	4.7	2065	0	659	149436
1993	156137	3976	2.6	2852	0	869	152415
1994	160446	4309	2.8	3668	0	988	155790
1995	165281	4835	3.0	4513	0	1023	159745
Avg % Inc							
1989-1995		4232	2.8				2.3
1990-1995		4574	3.0				2.5

Energy - Av. MW

Year	Basic	Annual Growth Av MW	%	EEI	L-S	LD-NUG	Primary
1989	15969	669	4.4	6	0	9	15954
1990	16257	288	1.8	66	0	46	16144
1991	16590	333	2.0	148	0	59	16383
1992	17322	732	4.4	235	0	75	17012
1993	17824	501	2.9	326	0	99	17399
1994	18316	492	2.8	419	0	113	17784
1995	18868	552	3.0	515	0	117	18236
Avg % Inc							
1989-1995		483	2.8				2.3
1990-1995		522	3.0				2.5

* Weather-Corrected Actual

2.4 Inputs to the Forecast

The short-term load forecast is prepared considering the following information.

(1) Regional Estimates - Each year a survey is made of all the Corporation's customers to determine their expectations for their own future peak demand. Known future customers are also taken into account.

(2) Economic Conditions and Trends - The most recent economic activity and energy price forecasts are assessed directly as well as used as inputs to a range of models for forecasting electricity demand.

(3) Forecasting Models - The Load Forecasts Department has estimated a variety of single-equation annual and monthly forecasting models. They range from the purely statistical analysis of past data (Box-Jenkins) to conventional structural econometric specifications. No one model has developed a clearly superior track record over the whole term of the forecast.

These three sources of forecast information are supplemented by other indicators where available (such as results from the end-use models).

This section provides a brief description of each of the above inputs. The forecast models are discussed in more detail in Appendix 2.

2.4.1 Regional Estimates

To initiate the short-term forecasting process, the Load Forecasts Department asks the regional offices to provide six years of estimates of the peak for each wholesale customer (municipalities and direct industrial) and total retail customers. The regional staff are supplied with the results from two time-series models provided by the Load Forecasts Department. With their knowledge of the local economy and the results of their consultation with large customers, they prepare an estimate for each month of the current year and the first forecast year. For the subsequent four years, only December forecasts are made. The customer survey takes place between February and May each year.

The regional estimates, which form the starting point for the regional detail for the Short-Term Forecast, were about the same as the 1989 Customer Survey for the year 1990, rising to a 1.2% increase over the year ago survey for the year 1994.

Table 2.4.1: Sum of Customers' Loads - MW

Average Monthly 1-Hour Non-Coincident Peaks

Year	1990 Customer Survey	1989 Customer Survey	Differences	% Change
1990	21940	21990	-50	-.2
1991	22998	22844	154	.7
1992	23973	23976	-3	0
1993	25042	24764	278	1.1
1994	26114	25781	333	1.3
1995	27172	N/A	N/A	N/A

The municipal utilities, the area offices, and the direct customers have the best and most detailed information about plans in their own neighbourhoods and businesses. They have the best perspective on new developments requiring electricity, on local business anomalies and on the continuity of existing sales. Their estimates are believed to be quite reliable for the near term.

2.4.2 Economic Conditions and Trends

Economic Outlook

The slower than expected decline in interest rates is having a significant negative effect on economic growth. The Ontario economy has been particularly hard hit in 1990, not just by high Canadian interest rates, but by the slump in car sales in the United States. The more rapid decline in U.S. interest rates ought to provide a modest boost to car sales there. Growth in Ontario's total output (GDP), which is now expected to be not much more than zero in 1990, could rise into the 1.5 to 2.0 percent range in 1991.

The recent Mid-East tensions have raised the price of oil and created additional forecasting uncertainties. There might be no major economic impacts, if other OPEC countries raise their oil production sufficiently to offset the loss of production from Kuwait and Iraq. However, there is a risk of war breaking out, which could totally disrupt oil production in the region. The resulting higher inflation would contribute to weaker economic growth in Ontario.

Ontario will lead Canada out of its recession, which has only just started. Growth is forecast to rebound in 1992 and to continue at a moderate level until the forecast horizon. The 1995 growth is higher due to a higher net migration to Ontario in the demographic forecast. Average growth over the entire period 1991 to 1995 is calculated at 3.5%.

Table 2.4.2: Economics and Forecasts Division's Outlook

Gross Domestic Product - $1981 Billion

	CANADA				ONTARIO			
	1989 Sept.	% Increase	1990* Sept.	% Increase	1989 Sept.	% Increase	1990* Sept.	% Increase
1989	459.869	2.70	457.333	3.00	183.001	2.50	185.370	2.84
1990	466.767	1.50	464.193	1.50	185.380	1.30	186.297	0.50
1991	479.370	2.70	470.228	1.30	192.054	3.60	189.650	1.80
1992	496.148	3.50	486.404	3.44	198.968	3.60	197.047	3.90
1993	513.513	3.50	503.428	3.50	205.335	3.20	203.943	3.50
1994	530.459	3.30	520.041	3.30	211.700	3.10	210.061	3.00
1995	549.037	3.50	537.722	3.40	218.054	3.00	218.044	3.80

* Historical numbers revised
Forecasts are from Short-Term Economic Forecast, September 1989 and 1990.

Energy Price Trends

Electricity prices are projected to increase by about 10% in real terms by 1995. In the short-term, petroleum product prices will be highly responsive to changes in the Gulf conflict. The extent and duration of the current oil crisis is difficult to project and our base case assumes oil prices coming back on our previous long-term trend around 1993/94. Natural gas prices have been under strong downward pressure as a result of an extended North American deliverability surplus. In the next five years natural gas prices are projected to grow more slowly, followed by a period of stronger price increases.

2.4.3 Short-Term Forecasting Models

Several models of the time series and econometric varieties have been built to assist with the forecasting process. The most sophisticated time series model the State-Space, incorporates provided forecasts by month for Ontario GDP on building permits. The econometric models, built on annual data, incorporate both a time series and an economic component. They also build in forecasts of economic variables including electricity price.

Greater detail concerning the model development, specification and forecasts is given in Appendix 2.

Table A2.1 in the appendix presents a comparison of the model projections along with the regional estimates and other forecast information used to determine the Short-Term Load Forecast.

2.4.3.1 Monthly Models

For several years the Load Forecasts Department has been gaining experience with several more advanced forecast modelling techniques. These use monthly data and comprise single and multiple variable time series methods. The forecasts prepared using these techniques perform best for time horizons less than about 18-24 months.

Since January 1988, the Load Forecasts Department has adopted a weather-correction methodology which adjusts for wind speed, illumination and humidity in addition to the temperature effects previously taken into account. This methodology was used to create a historical time-series of monthly weather-corrected data that goes back to 1971. The best models estimated by EPRI's Forecast Master software using these data had considerably better fits than the best models possible with actual data, attempting to account for weather effects within the equation itself. (The methodology used to weather-correct actual load data is described in Appendix 1).

The single variable time series model, called the Box-Jenkins technique after the original developers, presumes that all the information relevant to predicting the future of a variable is contained within the data history of the series to be predicted. Box-Jenkins models may be expected to forecast well in periods when the factors which affect the variable being forecasted continue their recent trend. For economic data this is unlikely to be longer than about two years and is often considerably less time. Predicted changes to the background environment of the forecasted variable that are out of keeping with recent trends will not be reflected in the projection made by the Box-Jenkins model. For this reason, little weight is currently being given to the Box-Jenkins forecast.

Multivariate time series methods are an elaboration of the single variable technique which permit key causal variables to be included in the forecasting equation. The form of multivariate time series analysis in Forecast Master which is used by the Load Forecasts Department is called State-Space modelling. The state-space model's forecast is still dominated by recent patterns in electricity use; a forecasted change in the trend of GDP growth has less impact on the forecast during the first year than the same change would have in one of the annual econometric models.

The State-Space model has picked up the recent sharp decline in weather-corrected energy demand and is projecting growth of only 1.1% for 1990, 2.0% for 1991 and 2.2% for 1992.

Tests done on the State-Space model with actual data in various time periods show that it reacts strongly to recent changes in pattern and growth. Due to this response, its projections are to be tempered by judgment in times of rapid change in pattern.

2.4.3.2 Annual Models

The error correction and partial adjustment models described in LF891211 have been re-estimated based on the latest historical data set available from Statistics Canada. The functional form has been augmented by the addition of some annual heating and cooling effect variables. The fitting statistics of the error correction model are better than those of last year, and it produces price and income elasticities in harmony with the more comprehensive long-term multi-equation models.

The average growth rate given by these models is 3.0% from 1990 to 1995, with the levels projected by the error correction model a little higher in the years 1991 to 1993, and a little lower at the forecast horizon in 1995.

2.5 Determining the Basic Load Forecast and the Unallocated Load

The customer surveys, economic trends and forecast model results constitute most of the data used in generating the forecast, but any other indicators of economic performance and electricity sales are considered as well. The forecast considers all available information taking into account the suitability of each methodology for projecting particular years of the forecast period.

The 1990 Customer Survey resulted in energy forecasts of 4.2% for 1990, 5.1% for 1991 and an average of 4.3% over the remaining years.

To make the total of the Customer Estimates reconcile to the Basic Load Forecast, an amount must be subtracted. This is called the unallocated load. It is not allocated to particular customers, but is applied on a customer class and regional level of disaggregation to the customer estimates.

The load growth forecast for Basic energy for 1990 is 1.8%, down 1% from LF891211. This follows the State-Space forecast, but with an upward adjustment of 0.7% intended to correct for the tendency of that model to undershoot. The state-space forecast has picked up the steep downtrend in monthly seasonally-adjusted, weather-corrected, load, but may have difficulty identifying the bottom of the trough of the cycle. The Customer Survey estimates a growth rate of 4.2% for 1990, but it was gathered during the early part of the year before load growth began to turn down. The customers evidently did not capture the forthcoming change in load growth caused by the downturn in the economy and the end of the boom in new construction.

For 1991, the Basic load growth forecast is 2.0%, again following the State-Space model. The State-Space model's track-record for 18 month-ahead forecasts has been very good. The rate it projects implies growth roughly at the rate of forecasted GDP growth for 1991, which appears reasonable.

The Ontario economy is forecast to rebound strongly in 1992. Following the 1982 recession, the level of load in 1983 was best predicted by models that did not anticipate or track the depth of the slowdown. This experience suggests that the 1992 level projected by the annual models from their 1989 base may be more valid than their forecasted growth rates relative to 1991. The error-correction model was selected because its elasticities correspond closely to those of the long-term annual econometric model (EEMO). Its level in 1992 results in a 4.5% growth rate for that year over the 1991 forecast developed from the monthly model results. The forecasts for 1993-95 are also generated with the error correction model. Table A2.1 shows a comparison of the model results and the customer survey results in terms of energy in average MW.

The large amounts of unallocated load in this year's forecast are due to the downturn in the Ontario economy, the end of the new construction boom with a slow recovery, and the cumulative effects of real price increases in electricity. Those effects become significant towards the forecast horizon and are captured by the annual error correction model. In addition, it is believed that our customers' forecasts were influenced upward by the transient load growth appearing in the last half of 1989 due to severe winter weather. All these conditions could not be known by our customers and these lead to the size of the unallocated load shown below in Table 5.0.

Table 2.5: Sum of Customer's Loads - MW

Average Monthly 1-Hour Peaks

Year	Customer Survey	Unallocated Load	Load Forecast (Basic)
1990	21940	-428	21512
1991	22998	-980	22018
1992	23973	-962	23011
1993	25042	-1339	23703
1994	26114	-1733	24381
1995	27172	-2036	25136

The amounts of unallocated load are much greater than those used last year in forecast LF891211.

2.5.1 Weather

The expanded Short-Term Forecast includes monthly forecasts of energy and peak demand. The monthly actual demands, as well as the annual actual totals, are strongly influenced by weather conditions. For the purpose of the forecast, normal weather conditions, as measured by the recorded averages, are assumed. For example, the December peak is assumed to occur on the most extreme weather day in December, which is assumed to have temperature, wind and illumination conditions equal to the typical extreme day in December.

2.5.2 Losses

In addition to estimates of customer demand, transmission losses are incorporated in the Basic Load Forecast. These losses averaged approximately 4.0% of customer energy for the period 1981 to 1983. Since 1984 losses have been gradually increasing, reaching 4.6% in 1986. In 1987 and 1988 losses dropped slightly to 4.5%. These higher than average losses will continue for a few more years due to the delay in obtaining adequate transmission out of the Bruce nuclear complex. There will be no relief from this situation until the new 500 kV line from Bruce to London is brought into service, currently scheduled for November 1, 1990.

Forecast energy losses are assumed to be 4.5% for 1990, 4.2% in 1991 and 4.2% for the remaining years of the forecast.

3.0 THE LONG-TERM BASIC LOAD FORECAST - METHODOLOGY AND ASSUMPTIONS

3.1 Methodology

This section introduces the methodologies used to prepare the Basic Load Forecast. In general terms, two approaches are taken to estimating electricity demand in Ontario: 'top-down' econometric modelling and 'bottom-up' end-use modelling. Both attempt to capture the effect of a large number of demographic, economic, energy market and technological factors on electricity demand in the long run. Because they do so at different levels of aggregation, the techniques available for extrapolation into the future differ.

The econometric approach relies on statistical analysis of past energy consuming behavior and forecasts of broad economic aggregates to generate estimates of future electricity requirements. The end-use approach tends to be so specific that historical data sets may not be available for statistical analysis. Instead, expert opinion on key technology or market trends are combined with very detailed forecasts of activity levels in end-use categories to derive the forecast. However, as data quality and detail improve and estimation techniques become more sophisticated, econometric results may increasingly determine many specific end-use forecasts. The hard distinction that once existed between engineering end-use (or process) models and econometric models is becoming less clear cut. The need for the load forecast to be tied to a broad scenario for the economy and at the same time be sufficiently detailed to be useful for analyzing demand management programs is pushing methodology to a common ground. The result will exploit the best of both worlds. Ultimately, end-use models are intended to represent both the Basic and the Primary Load Forecasts in an internally consistent manner.

Ontario Hydro uses both end-use and econometric modelling systems in preparing the Long-Term Basic Load Forecast. The strengths and weaknesses of these models are reconciled judgmentally in order to arrive at a recommended forecast for planning purposes.

In order to facilitate focusing on meaningful differences in the models' analysis of energy markets, both modelling approaches have the following features in common in the course of deriving Basic Load Forecasts:

(1) the same demographic, economic output, and energy price forecasts (summarized below in section 3.2).

(2) the same projections for natural load displacement non-utility generation, line losses and other statistical adjustments.

(3) the same data set (the Market Reference Dataset) with sectoral definitions that are the same for the industrial sector and almost identical for the commercial sector. The residential sector in the econometric model is almost equal to the residential sector plus 'other' in the end-use approach.

(4) the same short-term forecast by sector tuned to total system basic load in 1994.

(5) the same estimate of the impact of energy efficiency standards.

The end-use model forecasts are described in Section 4. This is the second year that the EPRI models REEPS, COMMEND and INDEPTH have been used to prepare the forecast. Background reports for each end-use sector are available, which analyze the forecast in greater detail.

The forecasts prepared by the econometric model, EEMO, are presented in Section 5. A report describing the model equations selected this year is available.

3.2 Discussion of Major Assumptions

The three most important factors in any model of the demand for electricity in the long run are the projections of the general level of economic activity, the price of electricity and the prices of other competing fuels. These factors can be incorporated into the models and the forecasting procedure in any of several ways. Because these factors are so central, each of the models has been run using similar assumptions. This approach allows the model results to reflect important differences in approach and other kinds of assumptions, and helps to explain the sources of the differences. The economic and energy price trends used throughout the load forecast are summarized below.

3.2.1 Economic Trends

Economic growth will follow the path outlined in the most-likely forecast of the Economics and Forecasts Division's Economic Outlook, Annual Review 1990. This outlook predicts real economic growth in Ontario averaging about 2.8% year over the period 1989 to 2000 and about 2.7% per year over the period 1989 to 2015. Following the trends in population growth, the economic growth rate is forecasted to slow down steadily.

Ontario population will grow at an average annual rate of 1.2% to the year 2000, taking population to just over 10.9 million. Between 1989 and 2015 population is projected to grow at an average 1.0% per year and reach 12.5 million.

Ontario labour force will grow at an average annual rate of 1.6% to the year 2000, when it will be over 6.2 million. Over the period to 2015, the average annual growth rate is 1.2% and the labour force reaches a level of 7.2 million.

Commercial floorspace (including apartments) will increase from its present level of 2.6 billion square feet to 3.1 billion square feet by 2000, an average annual rate of increase of 1.6%. By 2015 commercial floorspace increases to 3.7 billion square feet, an average annual growth rate of 1.4% a year from 1989.

Housing stock is projected to grow at 1.8% per annum to 2000, from 3.6 million in 1989 to 4.4 million in 2000. Between 1989 and 2015 housing stock is projected to grow at 1.4% per year and reaches 5.1 million units by 2015.

The outlook assumes that the stability of social, economic, and financial institutions will be retained. No international financial crisis will seriously affect the Canadian financial system. There will be no major supply disruptions in basic commodities, like fuels.

The forecast has not built in the cost of measures required to meet future, more stringent, environmental policies which could reduce GDP growth through lower productivity of capital. In preparing the outlook, this risk is offset against the likelihood that labour shortages in Canada and external demographic pressures could lead to even higher levels of immigration than currently projected. This would increase GDP growth through higher labour force growth. These are areas where long-term government policy has yet to be clearly formulated.

The 1990 Annual Economic Outlook forecasts a level of Gross Domestic Product (GDP) in Ontario of $367.7 billion (1981 dollars) in 2015. After taking into account the difference in the (1989) base since last year's forecast, the level of GDP in 2015 is up 6.7% from last year's economic outlook. The inflation outlook is unchanged from last year.

Table 3.2.1: Economic Outlook

	Ontario Real GDP (Millions of 1981$)				Ontario Consumer Price Index (1981 = 100)			
	Fall 1989	%*	Fall 1990	%*	Fall 1989	%*	Fall 1990	%*
1989(A)	185,370	2.8	185,370	2.8	156.0	5.8	156.0	5.8
1990	187,780	1.3	186,297	0.5	164.2	5.3	163.3	4.7
1995	220,877	3.3	218,044	3.2	212.6	5.3	209.4	5.1
2000	249,902	2.5	251,548	2.9	271.3	5.0	267.3	5.0
2005	279,994	2.3	287,391	2.7	346.3	5.0	341.1	5.0
2010	313,709	2.3	326,746	2.6	442.0	5.0	435.4	5.0
2015	346,360	2.0	367,700	2.4	564.1	5.0	555.6	5.0

* Annual Growth Rate 1989 and 1990, 5-year annual average 1995-2015
(A) Actual

3.2.2 Energy Prices

Table 3.2.2: International and Domestic Energy Prices - Reference Case Real 1990 Dollars

	Wholesale Prices			Ontario Retail Prices - Residential		
	International Oil U.S. Imports - F.O.B. US$/Bbl	Domestic Oil ORAC Cdn$/Bbl	Natural Gas (Toronto) Cdn$/Mcf	Fuel Oil ¢/L	Natural Gas $/Mcf	Electricity ¢/kW.h
1989	17.70	23.70	2.70	33.15	5.80	6.30
1990	22.80	27.50	2.58	36.40	5.42	6.38
2000	23.10	29.60	4.04	37.00	7.90	7.45
2010	25.60	33.00	5.20	39.90	9.75	7.65
2015	26.50	34.60	5.55	42.25	10.45	7.90

Source: Energy Price Trends, November 1990

Since Iraq's invasion of Kuwait, international crude oil prices have increased sharply in response to the political/military situation in the Persian Gulf. Prices have reached levels not seen since late 1985. In the short term, price development will be highly responsive to changes in the political/military situation in the Middle-East and any escalation of the conflict could push prices above US $40 per barrel. The extent and duration of the current oil price rise are difficult to project and our base case assumes oil prices coming back on our previous long-term trend around 1994/95. Our medium and long-term price projections for international crude oil have remained relatively unchanged.

A similar trend is expected for the domestic oil market. Canadian crude oil prices will follow the projected trend in international oil prices, subject to exchange rate and transportation cost adjustments. The posted prices in Edmonton will primarily be set relative to the spot prices of West Texas Intermediate crude. After the crisis is resolved, domestic crude oil prices are slightly lower (relative to the last year's forecast) as a result of a more precise quality adjustment. In the long run, domestic crude oil price projections are almost unchanged. In recent years, natural gas prices have been under downward pressure as a result of a North American natural gas surplus, strong gas-on-gas competition, increased share of direct purchases and buy/sell arrangements. In the next five years natural gas prices are projected to grow more slowly than in the last forecast followed by a period of stronger price increases. Our long-term price projections have remained relatively unchanged.

The most likely projection for wholesale and retail electricity prices ("reference case") is based on the price increases projected for the all-customers' average rate, as of July 1990 for the short-term, and as of October 1990 for the long-term, from the Corporate Financial Planning and Reporting Division. Although there is substantial uncertainty about the rate increases for particular years, there is a strong expectation of stronger pressure on rates up to 1993, with some easing off in 1994 after which they are expected to stay constant in real terms to 2005. After 2005 rates are expected to rise again in real terms to the end of the forecast period. The current forecast of electricity prices is substantially higher than last year.

A continuing weakness in the petroleum and natural gas markets and higher electricity rates during the last few years have deteriorated electricity's competitiveness, relative to both fuel oil and natural gas. An upward revision of electricity rates in the long run, with almost unchanged projections for other fuels, is leading to an even deeper and longer lasting electricity price disadvantage.

4.0 END-USE MODELS FORECAST

Introduction

End-use modelling uses a "bottom-up" approach to energy analysis. It starts with an initial stock of energy using devices. This stock is forecast to grow and alter in response to future sectoral activity levels. The energy efficiency of existing stock, penetration of new technologies with typically higher efficiency, and relative fuel share for each end-use are analyzed at a highly disaggregated level.

Each of the major energy using sectors is modelled separately. This analysis requires forecast of sectoral activity levels (in physical terms) such as residential housing stock, commercial floorspace and industrial output. The key sectoral activity forecasts were derived by the Economic Forecasts Section in a manner consistent with the Economic Outlook, 1990 Annual Review. To meet the extensive data requirements of the end-use models, that Section produced forecasts for commercial floorspace in each of 12 building types, over 40 industrial product forecasts for 13 industries and forecasts of three residential housing types. To produce these forecasts, econometric relationships were developed using explanatory factors such as population, labour force, disposable income, and service and industrial GDP forecasts at the two-digit level. All additional economic parameter forecasts needed to run the end-use models, such as age of head of household, persons per household, cost escalators and interest rates were also obtained from sources within the Division.

REEPS 1.0 (residential), COMMEND 3.2 (commercial) and INDEPTH (industrial) were used as the framework for the end-use analysis. Ontario Hydro's older End-Use Model (EUM) was used to address those industries not yet covered by INDEPTH.

4.1 Residential Sector

The residential sector end-use electricity demand was forecast using REEPS (Residential End-Use Energy Planning System) developed by EPRI (Electric Power Research Institute). REEPS is a microsimulation model that forecasts appliance acquisitions, operating efficiencies, and utilization rates for individual households. Household behaviour is modelled using the economic theory of consumer choice. Energy costs, the technological performance characteristics of alternative appliances and household attributes are explicitly modelled to influence consumer choice. REEPS uses the Residential Appliance Survey results for 1988 as a base to represent the household/dwelling characteristics of the population in Ontario. It also uses the results of the 1983 and 1986 surveys to calibrate the parameters of the model in order to simulate energy choices for new dwellings.

The main driving variable in the model is the number of single family households in the province. Single family dwellings include detached, semi-detached, row housing and duplexes. Apartments greater than five units are included in the commercial sector. The total number of households and the number of new occupied dwellings by housing type used in this year's forecast are presented in Table 4.1.1. The total number of households in single family dwellings is expected to grow on average at an annual rate of 1.2% per year throughout the forecast period. Table 4.1.2 shows the average annual growth rates for five year blocks up to 2015.

Table 4.1.1:Total Number of Households and Housing Completions By Building Type

Year	Total Number of Households	Housing Completions by Building Type Total Completions	Single Family (%)	Multi-Family (%)
1990	3,488,000	96,628	70	30
1995	3,846,000	74,885	68	32
2000	4,144,000	59,700	65	35
2005	4,401,000	57,256	59	41
2010	4,645,000	50,069	57	43
2015	4,886,000	49,192	62	38

Table 4.1.2: Total Number of Households: Single Family Dwellings

	Average Annual Growth Rate
1990 - 1995	1.8%
1995 - 2000	1.4%
2000 - 2005	1.0%
2005 - 2010	0.9%
2010 - 2015	0.9%
1990 - 2015	1.2%

The residential end-use forecast is described in some detail in 'The 1990 Residential Sector End-Use Forecast Report'.

The efficiency standards incorporated in this forecast, and their impact, are based on Ontario Regulations 340/89 and 689/89 as well as continuing detailed discussions with the Ministry of Energy. Further updates and extensions to these standards are expected. However, the level of uncertainty associated with these potential future standards precludes their inclusion in this forecast.

The following sections summarize the forecast for each of the end uses.

Space Heating:

The penetration of electric space heating equipment in single family dwellings has increased substantially during the last two decades. In 1973, only 6% of all single family houses in Ontario were electrically heated. This share went up to 12% in 1983 and reached 17% in 1987. At the present, there are about 484,000 all-electric houses in the province excluding those with heat pumps. With heat pumps (including add-ons), this figure increases to 580,000, 21% of all single family houses. Natural gas (58%) and fuel oil (21%) make up all the remaining space heating market. By 2015, it is expected that there will be approximately 1,000,000 all-electric houses, equivalent to 27% of the total stock. Natural gas will remain the dominant space heating fuel with a share of 59%.

Based on the 1000 Home Survey (1990), electric space heating Unit Electricity Consumption (UEC) estimates for the base year (1988) have been revised. It is now estimated that the annual UEC is 18,400 KW.h for single family homes with electric furnace, 15,400 KW.h for homes with electric baseboard and 9,000 KW.h for homes with heat pumps. By the end of the forecast period, these figures are expected to go down to 15,600 KW.h, 13,200 KW.h and 7,200 KW.h respectively. This is mainly driven by the anticipated improvement of the building shell. It is estimated that the proposed revisions to the Ontario Building Code will decrease the heating energy requirement by 15%. The UEC for space heating will also decrease as a result of higher penetration of heat pumps.

Approximately 22% of all electricity use in the residential sector is for space heating. This share is expected to fall to 20% by year 2015. Total electricity consumption for space heating is expected to increase from 8,430 GW.h in 1990 to 9,863 GW.h in the year 2000 and to 12,318 GW.h in 2015. This translates into a growth rate of 1.6% per year during the first decade and of 1.5% per year during the remaining 15 years of the forecast period.

Space Cooling

The air conditioning end-use, although small in the residential sector, has experienced fairly rapid growth during the last decade. This is due to a combination of favourable economic conditions and unusually warm weather over a long period of time. The most preferred system, central air conditioning, has increased its saturation rate from 13% in 1973 to 31.6% in 1989. Heat pumps add another 3.6% to this figure. The saturation of room air conditioning is 19.3% in the base year. As room air conditioners are gradually replaced by central units, their market share is expected to fall to 13.7% by the end of the forecast period. In year 2015, the saturations of central air conditioning and that of heat pumps are expected to be 53.4% and 5.1%, respectively.

In the absence of major technological advancements, it is reasonable to expect future efficiency improvements of 0.8% per year for both central air conditioners and heat pumps and 0.7% per year for room air conditioners. These trends, however, will be significantly advanced by the imposition of energy efficiency standards for air conditioning equipment. It is expected that the standards will improve new heat pump equipment efficiency by 10% starting in 1992, new central air conditioning equipment efficiency by 10% starting in 1994, and new room air conditioning equipment efficiency by 25% starting in 1994.

These efficiency gains will be partly offset by the effect of increasing household income on the demand for higher comfort levels. By 2015, the UEC of air conditioning equipment is predicted to decrease as follows: 23% for central air conditioning, 21% for heat pumps, and 30% for room air conditioning. Total electricity consumption for air conditioning in Ontario is estimated to be equal to 2.6 TW.h in 1990. By the end of the forecast period this figure will increase to 3.8 TW.h. This is equivalent to a growth rate of 1.6% per year.

Water Heating

In 1988, electricity consumption for water heating accounted for 19% of residential electricity consumption. By 2015, this share is forecast to be only 12% of total consumption. Such a decline is due to a combination of various factors: the imposition of appliance efficiency standards for dishwashers and clothes washers which will result in an 11% reduction in annual hot water energy requirements, the continuation of the decrease in the market share of electric water heaters in the future, and the expected decrease in the number of persons per household. In absolute terms, electricity consumption for water heating will remain approximately constant at the 1990 level (7 TW.h) throughout the forecast period.

The market share for electric water heaters has been continuously decreasing since 1973. In that year, 58% of single family dwellings had an electric water heater. By 1988, the market share fell to 48%. This is mainly a consequence of the Off-oil Program. As households replaced their oil furnaces with gas, they also switched to gas water heaters from electric. The decreasing trend is expected to continue throughout the forecast period. The market share for electric water heaters is expected to be 44% in year 2015. Natural gas is expected to be the predominant fuel for water heating with a 53% saturation, as is the case for space heating.

Refrigerators

Electricity consumption by refrigerators accounted for 13% of total residential consumption in 1988. This share is expected to decline to 7.5% by the end of the forecast period. The explanation for such a reduction is twofold. Firstly, since the refrigerator market is already saturated, further primary acquisitions are only a function of the increase in the number of households. Secondly, high rates of efficiency improvement coupled with new efficiency standards are expected to bring about a substantial decrease in the UEC of refrigerators.

In the absence of efficiency standards, an average efficiency improvement of 1.1% per year in new refrigerators would be assumed. The efficiency standards for refrigerators will significantly advance this development when they become updated in 1994 to match the 1993 U.S. levels. It is estimated that the standards will increase the efficiency of a new refrigerator by 45% over the 1990 levels. After changes in the average size and type of refrigerator are factored in, the net decrease in UEC is predicted to be around 33%.

Freezers

Freezers accounted for 4.2% of total electricity consumption in the residential sector in 1988. By 2015, this share is expected to fall to 2.5%. One interesting development in the case of freezers is the increasing preference for smaller units as a result of the decrease in the number of persons per household and the change in lifestyle (e.g. more eating out). Consequently, the average size of freezers has been continuously decreasing during the last 10 years.

It is assumed that the efficiency of freezers will increase at a rate of 0.8% per year during the forecast period. However, the updating of efficiency standards (matching the 1993 U.S. standards) in 1994 is expected to increase the average efficiency of a new unit by 35% over the 1990 level.

Cooking

According to the Canadian Facts Survey, 85% of the households in Ontario have a microwave and 83% of them use it frequently. 55% of the households use their microwave for warming leftovers while 26% use it for cooking as well. A microwave can do the same amount of cooking with 1/3 of the energy required by a conventional electric oven. These figures indicate that cooking is undergoing a major change in terms of energy requirements. The base year average unit energy requirement for cooking in the total housing stock is estimated to be 712 KW.h.

The substitution of microwave cooking for conventional oven is assumed to continue during the forecast period. Factors like changes in lifestyle (eating out, frozen dinners, etc.) and a decrease in the number of people per household will also exert a downward pressure on energy requirements per household. To reflect these developments, a modest efficiency improvement of 1.1% per annum is assumed throughout the forecast period.

The forecast of total electricity consumption for cooking indicates a rate of increase of 0.6% per year (from 1.7 TW.h in 1990 to 2.0 TW.h in 2015). The share of electricity consumption for cooking in total residential consumption is predicted to decrease from 4.2% in 1990 to 3.3% in 2015.

Dishwashers

Only the energy used by the motor component of dishwashers is accounted for under this category. The energy required for hot water use in dishwashers is not included here; it is captured in the water heater category. Consequently, total electricity consumption in the dishwashers category was only 0.9% of total electricity consumption in 1988.

Total consumption of electricity for dishwashers is expected to increase from 316 GW.h in 1988 to 448 GW.h in 2000 and to 589 GW.h in 2015. This implies a growth rate of 2.3% per year.

Other End-Uses

The "other" category in the residential sector includes all other end-uses that have not been previously discussed. The major ones are: lighting, clothes dryers, clothes washers, saunas, jacuzzis and whirlpools, television sets, audiovisual equipment, personal computers, electric fans in non-electric central heating, air cleaners, heat exchangers, humidifiers, dehumidifiers, car heaters, and, naturally, secondary electric heating. In 1989, the "other" category accounted for 34% of total residential consumption, the largest of the 8 major end-use categories analyzed in this forecast.

During the last 15 years, electricity demand by "other" grew at a rate of 5.3% per year. The corresponding growth rate for the "non-other" end-uses (combined) has been 3.8% per year. As a result of these growth patterns, the share of "other" in total residential electricity consumption increased from 27% in 1973 to 34% in 1989. Such a strong growth experienced by "other" was primarily the result of increases in the saturation of electric equipment and the intensity of electricity use. For instance, the saturation of clothes dryers went up from 43% in 1973 to 80% in 1988. The penetration rate of video cassette recorders escalated from 13% in 1984 to 59% in 1989. A similar growth was observed in colour television sets: their saturation increased from 36% in 1973 to 98% in 1988. More importantly, colour television sets were replacing black and white television sets which use 1/3 less electricity per unit, thus leading to a sharp increase in electricity consumption. In the future, the electrification process related to "other" is expected to continue as new appliances and new features/options in existing appliances are introduced into the market. It should also be noticed that many appliances presently included in the "other" category did not even exist 10 years ago.

The forecast results indicate that electricity consumption per household for "other" will grow at an annual rate of 1.7% per year. Taking into account the predicted increase in the number of households, total electricity consumption by "other" is expected to grow at a rate of 2.8% per year. By the end of the projection period, the total consumption of electricity by "other" is expected to reach 28.7 TW.h, 47% of total residential consumption.

Total Electricity Consumption

Tables 4.1.3 and 4.1.4 show the residential sector electricity consumption levels and the respective annual growth rates for the major end-use categories.

Total electricity consumption in the residential sector is expected to grow at a rate of 1.6% per year during the forecast period. The growth rate is forecast to be higher in the 1990-2000 period than in the 2000-2015 period (1.7% versus 1.5%). This difference is explained by the reduction in the growth in the number of households between these two time intervals (1.5% per year in 1990-2000 versus 1% per year in 2000-2015).

Table 4.1.3: Residential Electricity Consumption By End Use (GW.h)

	1990	2000	2015
Space Heating	8,430	9,863	12,315
Space Cooling	2,559	2,934	3,785
Water Heating	6,996	7,241	7,090
Refrigerators	5,009	4,721	4,638
Freezers	1,585	1,483	1,504
Cooking	1,727	1,931	2,019
Dishwashers	327	448	588
Other	14,245	19,956	28,738
Total	40,876	48,577	60,678

Table 4.1.4: Residential Electricity Consumption Growth Rates (% Per Year)

	1990 - 2000	2000 - 2015	1990 - 2015
Space Heating	1.6	1.5	1.5
Space Cooling	1.4	1.7	1.6
Water Heating	0.3	-0.1	0.1
Refrigerators	-0.6	-0.1	-0.3
Freezers	-0.6	0.1	-0.2
Cooking	1.1	0.3	0.6
Dishwashers	3.2	1.8	2.4
Other	3.4	2.5	2.8
Total	1.7	1.5	1.6

It is useful to compare this forecast of residential electricity demand against an alternative projection that assumed that the currently proposed Ontario government efficiency standards were not implemented. Table 4.1.5 presents the predicted consumption levels in the case of no efficiency standards, the current forecast (with efficiency standards), and the net effect of standards (both in absolute and in percentage terms).

Table 4.1.5: Impact of Standards On Total Electricity Consumption (GW.h)

Year	With Standards	Without Standards	Net Impact	% of Total Consumption
1990	40,900	40,900	0	0
1992	42,116	42,126	10	0.02
1994	43,683	44,007	324	0.07
1996	45,388	45,928	540	1.18
1998	46,938	47,745	807	1.69
2000	48,577	49,590	1,013	2.04
2002	50,211	51,261	1,050	2.05
2004	51,592	52,730	1,138	2.16
2006	53,443	54,710	1,267	2.32
2008	55,360	56,783	1,423	2.51
2010	56,886	58,385	1,499	2.57
2012	58,687	60,194	1,507	2.50
2014	59,823	61,257	1,434	2.34
2016	61,534	63,028	1,494	2.37

The net impact of standards rises from 0.07% of total demand in 1994 to 2.04% of total demand in year 2000. As the contribution of new stock to total stock composition increases, the impact of standards on the total stock increases over the forecast, reaching a maximum savings of 2.57% of total electricity demand in the year 2010. A slight decrease in the impact of standards should also be noticed towards the end of the forecast. This is due to the fact that some efficiency improvements are assumed to take place on a continuous basis in the absence of standards. Since the effect of standards is - to a large extent - the advancement of future efficiency gains, there is a point in time at which the absolute difference in electricity demand between the two forecasts begins to narrow.

Table 4.1.6 shows the impact of efficiency standards by end-use. The largest amount of savings in terms of GW.h are achieved in the refrigerators and water heating categories. The information provided in the last column of Table 6 reveals that both refrigerators and freezers will experience the highest savings (in relative terms).

Table 4.1.6: Impact of Standards By End-Use (GW.h)

End-Use	With Standards	Without Standards	Net Impact	% of Consumption
Space Heating	12,315	12,602	287	2.3
Space Cooling	3,785	3,817	34	0.9
Water Heating	7,090	7,536	446	5.9
Refrigerators	4,638	5,158	520	10.1
Freezers	1,504	1,680	176	10.5
Cooking	2,019	2,019	0	0
Dishwashers	588	588	0	0
Other	28,738	28,738	0	0

4.2 Commercial Sector

This year a P.C. based version of the COMMEND model (version 3.2) was used to conduct the building related portion of the commercial sector energy forecast. The non-building related energy demands (street-lighting etc) in the commercial sector were again forecast outside the COMMEND framework. The forecast is described in detail in "1990 Commercial Sector End-Use Forecast" and is presented here in summary form.

COMMEND relates energy use in the commercial sector to the stock of buildings and their energy consumption patterns. Energy use simulations are carried out for 12 different building categories. These building types represent most typical commercial categories including apartments, offices, retail stores, schools, hospitals etc.

The stock of buildings is measured in terms of square footage in each building category. As in other years, forecasts of floorspace by sub-sector were developed by the Economic Forecasts Section using single-equation econometric models. These models relate historical floorspace stock and construction to factors such as population, employment and Gross Domestic Product. The forecast of floorspace for the commercial sector as a whole shows a growth from approximately 2.6 billion square feet in 1989 to roughly 3.7 billion square feet by the year 2015 (see Table 4.2). This represents a growth rate of about 1.4% per year on average - significantly lower than the rate observed in the past 20 years. The main reason for this lower growth is related to changing demographics and an overall decrease in the growth rate of the population. In the future, growth in the predominantly institutional sectors of commercial floorspace (such as public service and schools) will be weaker than growth in the business services sectors; notably retail, office and accommodation. This long-term trend reflects the continuing shift in the composition of Ontario GDP towards the service-oriented sectors of the economy.

In terms of electricity demand, it is expected that the commercial sector will consume approximately 89 TW.h by the year 2015, up from the current level of roughly 47 TW.h. This represents a growth rate of about 2.5% in the long-term. In the shorter term, to 1995, expectations are that electricity demand will grow at a substantially higher rate of 3.8% per year. This stronger growth rate in the near term is related to: the continuing occupancy of newly constructed buildings (in spite of observed higher vacancy rates), increased penetration of electric space heating and air conditioning systems, and consistently strong growth in plug load related demand - particularly office machines and personal computers. In the longer term, the combined effects of a slowing down in the rate of construction and the increasing use of more efficient electrical systems will cause the rate of growth in electricity demand to moderate.

Table 4.2: Total Floor Stock By Sector (Millions Of Sq. Feet)

Sector	1989	2000	2015	Growth Rate 1989-2015
MULTIRES	838.73	1052.19	1211.35	1.42
OFFICES	381.20	502.79	640.72	2.02
ELEM/SECONDARY	211.64	231.45	234.37	0.39
COLLEGES/UNIV	97.82	99.95	107.40	0.36
HEALTH	84.30	110.99	159.64	2.49
PUBLIC SERVICE	70.17	74.59	78.25	0.42
RETAIL	250.90	318.52	395.19	1.76
ACCOMODATION	97.13	117.20	142.71	1.49
RECREATION	52.15	60.14	66.59	0.94
RELIGIOUS	64.11	68.25	72.51	0.47
WAREHOUSES	323.22	365.07	424.18	1.05
MISCELLANEOUS	80.98	100.84	123.02	1.62
TOTAL	2552.35	3107.51	3678.93	1.42

* Average Annual Percent Change

4.2.1 Analysis By Major End Use

COMMEND permits a disaggregated analysis of energy use for 10 end uses by efficiency and utilization components. In the following discussion, "efficiency improvement" signifies decreased energy consumption per unit of service due to mechanical or technological changes. "Utilization changes" refer to changes in the amount of energy services required. The resulting energy demand per square foot takes account of both efficiency and utilization impacts.

SPACE HEATING: Changes in fuel share are expected to have the biggest impact on electricity demand in the future. Currently, natural gas is the predominant fuel used for space heating with approximately 70% of all floorspace being heated by gas. Electricity (20%) and oil (10%) make up the remainder of the space heating market. By the year 2015, electricity is projected to increase its share of the market to about 35%, while gas will fall slightly and oil will all but disappear as a fuel for space heating.

There are a number of reasons for these changing share forecasts. First, it is forecast that, in the long term, the trend in the price of electricity will become more favourable (relative to the other fuels) thus making electric systems more attractive. Second, heat pumps, with their high efficiency levels and dual heating/cooling capabilities, will be a preferred system for many decision-makers. Third, baseboard heaters will continue to be installed in many buildings because of their individual cost and control features. In this sense, baseboard heaters and heat pumps share the feature that non-price aspects often determine system selection.

Turning to efficiency and utilization issues, it is expected that more efficient building envelopes and heating system designs will combine to make heating in all new buildings, regardless of fuel type, more efficient. For electrically heated buildings, efficiency levels in new buildings will be between 10% and 25% better than the existing stock, depending on building shell and equipment mix. As well, older buildings will experience some improvements in efficiency due to shell and equipment retrofits. From the perspective of changes in utilization, it is expected that although internal heat gains will cause utilization to decrease, these decreases will be partially off-set in some sectors by longer operating hours and increased emphasis on comfort.

The net result of the floorspace, share, efficiency and utilization forecasts shows space heating electricity demand growing from 3600 GW.H to 8000 GW.h by 2015, a growth rate of roughly 3% per year on average.

AIR CONDITIONING: Air conditioning systems will continue to be installed in more and more buildings - both in new buildings and retrofits to existing buildings. As a result, the average penetration of electric air conditioning in the commercial sector is forecast to increase from its current level of 50% to about 70% by 2015. Like their space heating counterparts, air conditioning systems will become increasingly efficient reflecting the impact of new technologies such as heat pumps and energy efficient chillers. Counter-balancing these efficiency gains, however, is the effect of greater use of the equipment. Increased usage will result from the combined effects of heat gains from the increase in other building loads and longer hours of operation. The net effect is that air conditioning demand should grow at more than 2.5% per year with sectors such as apartments, offices and retail experiencing growth rates close to 3% per year on average.

LIGHTING: The largest single user of electricity in the commercial sector is lighting. At present it accounts for roughly 35% of total building related commercial sector electricity demand. By the year 2015, its contribution is expected to fall to about 26%. The main reason for this decline is the increased efficiency associated with the installation of energy efficient lighting systems - in particular the replacement of 40 watt bulbs by 34 watt bulbs in the existing stock and the installation of new technologies such as electronic ballasts into new stock. For new stock, an average efficiency gain of about 20% - 25% over the existing level is expected.

As with the other end uses, trends in utilization will act to counter-balance efficiency gains. This is especially true in the retail sector where longer opening hours for stores are already being observed. Thus it is expected that more floorspace and increased utilization will negate many of the efficiency improvements in lighting. Demand is expected to grow from the current level of about 14 TW.h to 19 TW.h by 2015.

VENTILATION: This end use is linked to space heating and air conditioning since, as the requirement for heating or cooling changes, so too will the amount of ventilation. Many of the trends with respect to usage identified for space heating and air conditioning have implications for ventilation as well. For instance, as air conditioning demand increases due to increases in interior loads, so too will ventilation loads. More efficient pumps and variable speed drive motors will increase the average efficiency of ventilating systems. As a result, the forecast for ventilation is for modest growth of about 2% per year.

OFFICE EQUIPMENT: This year's forecast represents the first time that office equipment (typically made up of computers, photocopiers, facsimiles etc.) was analyzed as a separate end use. A base year scenario was developed that estimated a current demand of about 4.4 TW.h from office equipment. Recent evidence suggests that this type of equipment, although penetrating the market at a rapid rate, has not achieved saturation levels. It is expected that as the economy moves more and more towards an information base, these technologies will become indispensable. The forecast is for strong growth at slightly more than 4% per year, and will be especially strong in the office, retail and health sectors.

MISCELLANEOUS EQUIPMENT: This category now includes equipment such as elevators, escalators, walkway heaters and medical diagnostics. It is expected that, with a predominance of large buildings in the construction forecast, demand from elevators/escalators will rise faster than floorspace. Increased penetration and use of diagnostic equipment will be an important factor in the health care sector. The forecast is for a growth rate for miscellaneous of 3.6% per year.

Water heating, cooking, refrigeration and exterior lighting were also forecast within the COMMEND framework. These end use forecasts are also presented in Table 4.2.2.

NON-BUILDING RELATED DEMAND: The forecast focusses on street lighting, municipal waterworks and construction. These demands are related to the growth in the housing stock. For street lighting, the mix of various bulb types was explicitly taken into account. The forecast for non-building related electricity demand is for growth from the current level of 6.6 TW.h to approximately 13.2 TW.h by 2015.

Total commercial sector electricity demand is expected to grow at about 2.5%. The composition of final demand by building type is given in Table 4.2.1 and by end use in Table 4.2.2 and Figure 4.2.3.

The detailed background report gives full disaggregation and explanations for each of the floorspace, fuel share, energy utilization index and end-use forecasts.

Table 4.2.1: Total Commercial Sector Electricity Demand By Building Type Type
(GW.h)

Sector	1989	2000	2015	Growth Rate 1989 - 2015*
MULTIRES	6275	8951	11932	2.50
OFFICES	11151	16375	24388	3.06
ELEM/SECONDARY	1705	1958	2178	0.95
COLLEGES/UNIV	1233	1328	1572	0.94
HEALTH	1694	2442	4034	3.39
PUBLIC SERVICE	828	943	1111	1.14
RETAIL	7537	10463	14858	2.64
ACCOMODATION	2806	3584	4860	2.14
RECREATION	1184	1486	1868	1.77
RELIGIOUS	420	459	521	0.83
WAREHOUSES	2713	3156	3895	1.40
MISCELLANEOUS	2349	3093	4173	2.23
TOTAL BUILDING RELATED	39895	54238	75390	2.48
TOTAL COMMERCIAL	46586	65796	88830	2.51

*Average Annual Percent Change

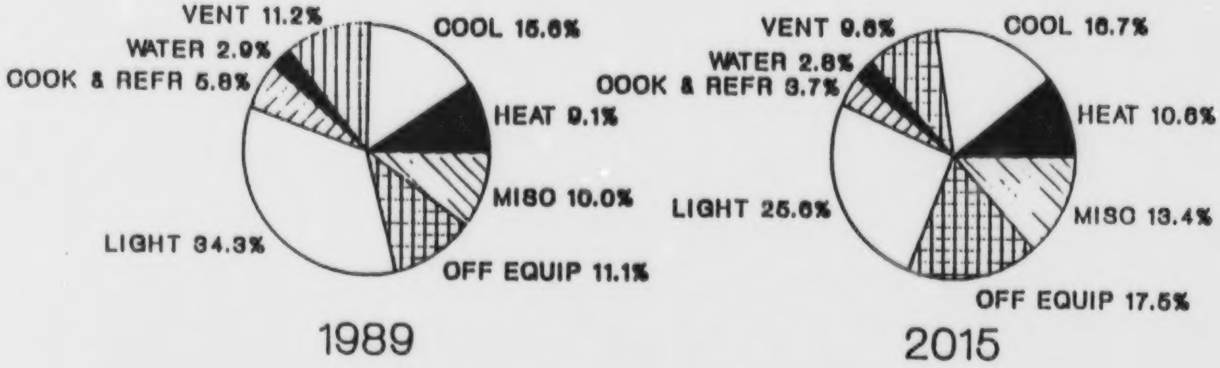
Table 4.2.2: Total Building Related Commercial Sector Electricity Demand By End Use
(GW.h)

End-Uses	1989	2000	2015	Growth Rate 1989 - 2015*
SPACE HEATING	3613	5520	8005	3.11
SPACE COOLING	6240	8792	12560	2.73
VENTILATION	4461	5698	7258	1.89
WATER HEATING	1173	1634	2146	2.35
COOKING	710	823	1001	1.33
REFRIGERATION	1602	1708	1798	0.44
OUTDOOR LIGHTING	2101	2517	3039	1.43
INDOOR LIGHTING	11585	13679	16275	1.32
OFFICE EQUIP.	4427	7599	13218	4.30
MISCELLANEOUS	3983	6266	10090	3.64
TOTAL BUILDING RELATED COMMERCIAL SECTOR ELECTRICITY	39895	54237	75390	2.48

*Average Annual Percent Change

Figure 4.2.3

COMMERCIAL ELECTRICITY DEMAND
SHARE OF TOTAL



4.3 Industrial Sector

The industrial sector covers the resource, construction and manufacturing sectors. This year the forecasts for four industries (cement, iron and steel, industrial chemicals and pulp and paper) were produced using a series of new industry-specific models. These models were developed by the Load Forecasts Department using EPRI's INDEPTH modelling framework. These four industries accounted for 47% of total industrial electricity demand in 1989, and 55% of total industrial energy demand. Forecasts for the remaining industries were produced using the industrial sector of our older end-use model (EUM) as in previous years.

INDEPTH provides a flexible framework for load forecasting and the analysis of demand management programs, allowing the analyst to include much greater detail than is possible in the EUM. Each industry is defined in terms of a number of processes, each process having various competing technologies available to accomplish the task at hand. Technologies are selected on the basis of minimum life cycle cost, unlike the EUM which relies strictly on the analyst's judgement. This approach requires that the capital cost, operating cost and energy consumption be specified for each technology as well as various financial parameters such as the discount rate. The analyst is able to test the sensitivity of the most-likely forecast by running the model using different input assumptions (eg. future energy prices).

Data for each INDEPTH industry were gathered by consultants directly familiar with the industry. The very detailed nature of these models makes secondary information insufficient for model specification. In addition to the four INDEPTH-modelled industries, an INDEPTH database for the mining, milling, smelting and refining industry was completed by an external consultant. Although an INDEPTH model has not yet been built for this latest industry, these data were considered in this year's forecast. Forecasts and detailed analyses of the main products of each industry are provided by the Economic Forecasts Section. Output is used in physical unit terms, where possible. Value added is used as the measure of output for those industries where the range of products would make it difficult to specify output in physical terms. Details can be found in the Physical Unit Forecasts report issued by that Section.

The end-use forecast for the industrial sector is summarized in Tables 4.3.1 (growth rates) and 4.3.2 (levels) below. Table 4.3.3 gives the relative importance of each industry in terms of % share of electricity consumption in 1989.

The 1990 industrial forecast does not incorporate the effect of government legislated standards. At this point, potential standards are being discussed for motors and lighting. However, it is as yet uncertain what the standards will be and the date of their implementation. Analysis of the impacts of any standards on industrial sector demand will be carried out once decisions on these standards have been firmed up.

Table 4.3.1: Growth In Electricity Demand By Industry

	Average Annual Growth	
	1989-2000 %	2000-2015 %
Mining, Milling, Smelt, Refining	-0.1	1.2
Food & Beverage	2.1	2.0
Rubber & Plastic	4.9	3.0
Leather, Primary Textiles	0.6	0.9
Pulp & Paper	1.5	2.1
Iron & Steel	2.2	1.7
Fabricated Metal Products	2.8	2.9
Automobile Assembly	2.8	1.3
Automotive Parts, Iron Foundries	4.0	2.1
Electrical & Electronic Parts	4.4	3.0
Non-Metallic Minerals	0.9	1.2
-Cement	1.2	2.1
Petroleum Refining	2.2	1.8
Industrial Chemicals	1.9	2.4
Other	5.7	2.6
TOTAL INDUSTRIAL	2.4	2.1
TOTAL INDUSTRIAL (1989-2015)	2.2	

Table 4.3.2: Electricity Demand By Industry

	1989	2000 (GWH)	2015
Mining, Milling, Smelt, Refining	6504	6460	7680
Food & Beverage	1934	2430	3257
Rubber & Plastic	1122	1895	2951
Leather, Primary Textiles	685	728	828
Pulp & Paper	8333	9842	13521
Iron & Steel	6240	7887	10202
Fabricated Metal Products	1785	2429	3725
Automobile Assembly	1162	1575	1911
Automotive Parts, Iron Foundries	1786	2745	3777
Electrical & Electronic Parts	1229	1966	3073
Non-Metallic Minerals	2212	2437	5371
-Cement	834	953	1311
Petroleum Refining	2228	2844	3741
Industrial Chemicals	6598	8112	11611
Other	5497	10073	14760
TOTAL INDUSTRIAL	47315	61423	83973

Table 4.3.3: Share Of Industrial Electricity Demand 1989

	Percent
Mining, Milling, Smelt, Refining	14
Food & Beverage	4
Rubber & Plastic	2
Leather, Primary Textiles	1
Pulp & Paper	18
Iron & Steel	13
Fabricated Metal Products	4
Automobile Assembly	2
Automotive Parts, Iron Foundries	4
Electrical & Electronic Parts	3
Non-Metallic Minerals	5
-Cement	2
Petroleum Refining	5
Industrial Chemicals	14
Other	12

The rationale behind the projection for the four largest industries is summarized below. A more detailed discussion of the technology analysis for all 18 industries studied can be found in the 1990 Industrial End-Use Forecast Report and accompanying Appendix.

Mining, Milling, Smelting and Refining (Sic 06,07,08,09,295):

Mineral output growth rates are forecast as follows:

		Average Annual Growth Rate	
		1989-2000 (%)	2000-2015 (%)
(tonnes)	gold	-2.8	-1.4
"	uranium	-12.1	3.3
"	copper	1.7	1.6
"	nickel	0.9	1.9
"	zinc	4.0	1.2
"	iron ore	(mine closure)	
"	other minerals	1.7	1.6

In general, electricity use in mining is expected to increase at a faster rate than production. A major factor is the growing trend toward all-electric mines. Electric-powered Load-Haul-Dumps (LHDs) are expected to substitute for diesel equipment. Electric LHDs are cleaner, quieter and more productive and also offer an opportunity to reduce ventilation electricity requirements.

It is technically possible that the electricity savings resulting from reduced ventilation could more than offset the electricity consumption of the electric LHDs themselves. However, because of the trend towards more conservative health and safety regulations, it is assumed in this forecast that the ventilation savings will be smaller. Electric LHDs are particularly suited to bulk mining in base metal mines.

Factors expected to reduce electricity demand include: increasing use of electric-hydraulic drills rather than pneumatic drills; more efficient hoists and fans; more efficient mining methods such as bulk mining.

In order to meet acid gas emission limits imposed by the Ontario government, a number of measures have been taken in the past and further measures are being planned. Rejection of high-sulphur low-nickel pyrrhotite during the milling process in favour of low-sulphur high-nickel minerals is a major step in this direction. Efforts at smelters and refiners will also assist in lowering emissions. Flash smelting of nickel-copper concentrate (requiring increased oxygen use) is being planned for INCO's Coppercliff plant. This increased oxygen use will result in an increase in electricity demand for oxygen production. It is assumed that oxygen production will be carried out on-site and will result in an increase in electricity intensity for this industry. The Kidd Creek copper smelter is also looking at increased oxygen use to increase output capacity.

Continuing improvements in process control should result in reductions in electricity use for nickel and copper refining. Little change in electricity efficiency is expected for zinc or uranium refining. Output capacity increases at Kidd Creek's zinc plant would be expected to increase electricity intensity somewhat.

The above considerations lead to the following changes in relative electricity intensity by the end of the forecast period:

	1989	2015
Mining/Milling		
gold	1	1.04
uranium	1	1
copper/nickel	1	0.9
other	1	1
Smelting/Refining		
zinc	1	1.1
copper/nickel	1	0.98
uranium	1	1

Electricity use for this industry is forecast to decline at an annual average rate of -0.1% to 2000. Annual growth of 1.2% is forecast for 2000-2015.

Pulp and Paper (SIC 271)

Product growth rates are forecast as follows:

		Average Annual Growth Rate 1989-2000 (%)	Average Annual Growth Rate 2000-2015 (%)
(tonnes)	newsprint	1.2	1.0
"	paperboard	1.6	2.5
"	printing/writing paper	3.7	2.9
"	wrapping paper	-0.1	0.2
"	tissue & building paper	2.8	2.7
"	export pulp	1.0	1.5

Current electricity consumption by the industry can be broken down as follows: newsprint 49%, printing/writing paper 23%, export pulp 7%, all others 21%.

A major difference in this year's forecast is the explicit analysis of the impact of increased paper recycling on electricity demand. The impact is twofold, affecting the level and grade of paper production and the actual method of production itself. To some extent these impacts are offsetting with the increased electricity intensities of higher grade paper being offset by the decreased electricity demand of waste fibre use.

In the INDEPTH model framework, fibre for pulp and paper production can be supplied by softwood, hardwood or waste paper. Waste paper sources are further classified as old newsprint (ONP), old corrugated containers (OCC) or high grade de-inked (HGD). These are three of five industry-accepted waste paper grade groups, the other two being boxboard cuttings and mixed papers. ONC, OCC and HGD, however, account for over 90% of all waste paper used. These waste fibre sources are not interchangeable and each fibre source can only be used in particular grades of products.

The current composition of newsprint production is predominantly groundwood (GW), with small contributions from low quality TMP and recycled fibre. The electricity intensity of each of these pulping operations is: GW (1620 kwh/tonne), TMP (2500 kwh/tonne) recycled fibre (290 kwh/tonne). The actual papermaking end of the operation consumes 695 kwh/tonne. Throughout the forecast period two trends are seen: the increasing utilization of waste fibre and the gradual shift from low commodity grades (unbleached GW, unbleached TMP) to premium grades (bleached TMP, bleached CTMP). For each tonne of waste paper substituted for virgin fibre in newsprint, approximately 1000 kwh is saved, of half of the total amount required per tonne of newsprint (assuming current production composition). For each tonne of bleached TMP substituted for unbleached GW, electricity intensity is increased by 930 kwh per tonne. It is forecast that by 2015, GW pulping will be phased out, with 1/3 of production using waste fibre and all virgin fibre production using bleached TMP/CTMP.

In the case of fine quality printing and writing papers, quality requirements are much higher and existing waste paper technologies do not meet standards. It is expected that new technologies will overcome this barrier and that HGD fibre will constitute 20% of the fibre furnish by 2015. TMP is also expected to replace GW and account for 20% of production by that time. Penetration of TMP is expected to be dampened somewhat by the focus on higher quality freesheet papers which are characterized by higher chemical pulp content.

Two other pulping technologies which are expected to make headway during the forecast period are oxygen delignification and kraft alcohol pulping. There will be virtually no impact on electricity consumption by the former. The latter would decrease the electricity intensity of hardwood kraft pulping by 20 %. The net decrease in electricity consumption of the industry as a whole would be under 1%.

Twin-wire forming is a well-recognized state-of-the-art papermaking technology which produces superior paper quality. Decreased electricity consumption in newspaper and writing paper production will result from adoption of this technology. Gas and electric impulse drying are also expected to see commercial application by the mid 1990s. Gas impulse drying would lead to decreased electricity intensity, while significant increases would result from the penetration of electric impulse drying. The net effect of these counterbalancing effects is that minimal change in the electricity intensity of the papermaking end of operations is forecast.

The above considerations lead to the following changes in relative electricity intensity by 2015:

	1989	2015
newsprint	1	1.16
paperboard	1	1.09
printing/writing paper	1	0.98
wrapping paper	1	0.78
tissue & building paper	1	0.77
export pulp	1	1.07

Growth in electricity demand for the industry is forecast at 1.5% till the year 2000, and 2.2% for the period 2000-2015.

Primary Iron and Steel (SIC 291)

The INDEPTH model is driven by the demand for 10 key finished and semi-finished steel products. Forecast growth rates are given below:

		Average Annual Growth Rate	
		1989-2000 (%)	2000-2015 (%)
(tonnes)	Flat-rolled products		
"	ingots	-5.0	-2.0
"	hot-rolled sheet/strip	2.0	1.3
"	cold-rolled sheet/strip	3.0	1.2
"	galvanized sheet	3.7	2.0
"	steel plate	-1.2	1.1
"	tin plate	1.2	1.0
"	Billet products		
"	bars	0.7	1.0
"	rods	1.5	0.8
"	structural shapes	2.3	0.9
"	Bloom products	1.5	2.8

The future production split between integrated and scrap-based EAF (electric arc furnace) facilities is a key variable in determining electricity demand. On a per ton of raw steel basis, electricity use by EAFs is 8-10 times that of BF/BOF (blast furnace/basic oxygen furnace) facilities. Currently in Ontario, 15% of raw steel is produced in EAF facilities. The percentage of steel produced in EAF facilities has been increasing steadily throughout North America as a result of lower capital and operating costs. A major factor limiting EAF growth is difficulty in penetrating the important flat-rolled product market. An important reason for this is the higher levels of residuals in steel made from scrap, making it difficult to use in certain products. Steel made from scrap cannot easily be cold-rolled to produce a higher quality product. Although the supply of scrap in Ontario is not a problem, the supply of low-residual scrap is limited. It is thus anticipated that production of raw steel in integrated mills will remain relatively stable over the forecast period, and that all additional growth in production will come from scrap-based EAF mills. The percentage of raw steel produced in scrap-based mills is expected to rise from 15 to 40% by 2015. A potential risk to this forecast is the growing concern over the greenhouse effect. Given the large CO2 emissions from integrated mills, production from scrap-based EAF facilities could be given a further push.

The average age of coke ovens is quite high. Integrated mills are, therefore, looking at ways to maintain production levels while mitigating their environmentally damaging effects. Pulverized coal injection, a technology already commonly used in Europe and Japan, is expected to be used to reduce the amount of coke used in blast furnaces. The concomitant requirement for oxygen enrichment of the hot blast will result indirectly in increased electricity use for oxygen production in the chemicals industry. (This factor has been taken into account in the analysis of the latter industry). Continued use of electric ladle pre-heat and electric ladle refining, used to increase steel quality will result in increased electricity intensity.

In the past decade mini-mills have roughly doubled the productivity of their EAFs while reducing their electricity requirement by 20%. Based on technologies being used or developed in other parts of the world, there is still room for efficiency improvement. Scrap preheating, widely used outside North America, reduces electricity demand by using waste heat. The increased use of oxyfuel burners and oxygen lancing, two technologies already in use, will lead to further declines in the electricity intensity. The Energy Optimizing Furnace (EOF) has been proposed as a substitute for the EAF. As a coal-consuming process, its future was considered to be environmentally uncertain and so was not included in the forecast.

The growth in demand for highly processed steel products (eg. cold rolled sheet and strip, galvanized steel) will tend to increase electricity intensity during steel finishing operations. Penetration of thin slab casting and strip casting as well as increased continuous casting will result in reduced electricity use. By improving steel yields, these casting technologies reduce raw steel production requirements and thus indirectly overall electricity use. Increasing use of direct roll for billet production will lead to increasing electricity intensity for this product group.

The above considerations are taken into account by the INDEPTH model in deriving the following changes in relative electricity intensity by 2015:

	1989	2015
raw steel		
integrated	1.0	1.12
mini-mills	1.0	0.82
flat-rolled products	1.0	0.89
billet products	1.0	1.09
bloom products	1.0	0.85

Growth in electricity demand for the industry is forecast at 2.2% till the year 2000, slowing to 1.7% for the period 2000-2015.

Industrial Chemicals (SIC 371,3721)

The INDEPTH model of the industrial chemicals industry is driven by the production of seven key chemicals. Product growth rates are forecast as follows:

		Average Annual Growth Rate 1989-2000 (%)	Average Annual Growth Rate 2000-2015 (%)
(tonnes)	chlorine/caustic soda	1.3	1.4
"	sodium chlorate	1.8	1.0
"	industrial gases		
	nitrogen	1.1	1.4
	oxygen	1.6	0.9
"	ammonia	-5.6	1.9
"	ethylene	3.2	4.3
(VA)	other	2.2	2.3

Chlorine and caustic soda are co-produced in electrolytic cells. The three types of cells currently in use, in decreasing order of electricity intensity are: mercury, diaphragm, membrane. Mercury cells produce the purest product. However, concerns over mercury pollution prohibit future expansion of this technology. Diaphragm cells account for over 80% of production in Ontario. Membrane cells are the newest technology and are generally considered the cell of choice for new plants or retrofits. It is expected that all plants will have converted to membrane cells by the end of the forecast period. Given ongoing advances in membrane cell design it is likely that newer designs will feature even lower electricity intensity.

Sodium chlorate is the second most important electrolytic chemical produced in Ontario. Sodium chlorate is produced in two plants in Ontario both of which use "dimensionally stable" anodes--- the major process innovation over the past 20 years. No new technologies are currently available or foreseen to reduce electricity use.

The vast majority of industrial gases are produced using a cryogenic air separation process. Electricity is used to power the large compressors used in the process. New technologies currently available are economic only for low volume applications and are unsuitable as technologies for large volume industrial gas plants. The forecast assumes that the cryogenic process will continue to be used. Electricity intensity will decline as new, more efficient plants are built and as digital control becomes more widespread and sophisticated.

Only two plants producing ammonia are currently operating in Ontario. The Nitrochem plant is quite old and uses substantially more natural gas and electricity per tonne than the modern C-I-L plant. It is expected that any future capacity expansion will be similar in design to the C-I-L plant. As a result electricity intensity is expected to decline.

Either steam turbines or electric motors are used to provide motive power for ethylene production. An increasing proportion of motive power is being provided by electric motors due to their lower capital cost and increased reliability. It is expected that this trend will continue. Offsetting this increase somewhat will be improvements in process control.

The above analysis leads to the following changes in relative electricity intensity:

	1989	2015
chlorine/caustic soda	1.0	0.83
sodium chlorate	1.0	1.0
industrial gases	1.0	0.91
ammonia *	1.0	1.0
ethylene	1.0	1.25
other	1.0	1.25

* Impact of Nitrochem excluded. All future expansion assumed using CIL plant design.

Electricity demand for this industry as a whole is forecast to grow at 1.9% until 2000 and 2.4% from 2000 to 2015.

4.4 Transportation Sector

The transportation sector, although a large consumer of energy, accounts for only 0.3% of electricity demand. The majority of this electricity use is in the road transport and urban transit segment which is composed of the energy requirements of subways, streetcars and trolley buses. As was the case last year, Ontario Hydro turned to the forecast produced by the Ministry of Energy as the basis for its own forecast. Recognizing growing environmental concerns and the potential impact on the internal combustion engine, Ontario Hydro completed a preliminary study on the future penetration of electric vehicles (EVs) and the electricity demand associated with their use. The transportation sector forecast includes this latest estimation. The details of the EV analysis are contained in a separate report.

4.5 Agriculture Sector

Electricity use by the agricultural sector is comprised of two components:

(1) residential use by farming households,
(2) operational use in running farming equipment.

The first component is aggregated into the Residential Sector. The remainder is referred to as the Agricultural Sector and is incorporated in the summary table under the 'other' category.

Details of the forecast are contained below.

1990 End-Use Agriculture Sector Forecast

Farm Type	1989 Electricity Share %	GWH 1989	GWH 2015
Greenhouses	4.5	45	59
Poultry	11	109	210
Tobacco	4.5	45	33
Grain	13	130	317
Dairy	37	366	
Swine	17	173	838
Miscellaneous	13	124	
Total	100	992	1457

Together, dairy and hog farms account for over 50% of the electricity use in this sector. The end-use breakdown underlying this forecast is based on the "Ontario Hydro Agricultural Study", Barakat, Howard and Chamberlain (1989).

4.6 The 1990 End-Use Forecast

End-Use Forecast (TW.h)

Year	Residential	Commercial	Industrial	Transportation*	Other**	Total
1989(A)	40.1	46.6	47.3	0.4	1.2	135.6
1990	40.9	48.7	45.6	0.4	1.3	136.9
1995	44.5	58.2	54.9	0.4	1.4	159.5
2000	48.6	65.8	61.4	0.6	1.5	177.8
2005	52.5	73.2	68.7	0.6	1.6	196.6
2010	56.9	80.9	76.2	0.8	1.7	216.5
2015	60.7	88.8	84.0	0.9	1.8	236.2
Growth Rates						
1989-1995	1.8	3.8	2.5			2.8
1989-2000	1.8	3.2	2.4			2.5
1989-2010	1.7	2.7	2.3			2.2
1989-2015	1.6	2.5	2.2			2.2
1995-2015	1.6	2.1	2.2			2.0

Basic	Total	Load Displacement	T & D Losses	Adjustment***	Basic Electricity Demand
1989(A)	135.6	6.0	11.4	0.2	140.8
1990	136.9	6.2	10.7	0	141.4
1995	159.5	6.8	12.6	0	165.3
2000	177.8	7.5	14.0	0	184.3
2005	196.6	7.9	15.5	0	204.2
2010	216.5	8.2	17.1	0	225.4
2015	236.2	8.6	18.7	0	246.3
Growth Rates					
1989-1995					2.7
1989-2000					2.5
1989-2010					2.3
1989-2015					2.2
1995-2015					2.0

* Road Transport and Urban Transit
** Pipelines; Agricultural Operations
*** Ontario Electricity not sold by Ontario Hydro; Statistical differences

5.0 ECONOMETRIC ENERGY MODEL OF ONTARIO - EEMO

EEMO is a multi-equation econometric model of energy use in Ontario developed by the Load Forecasts Department at Ontario Hydro. It is designed to forecast the level of energy consumption for Ontario as a whole by consuming sector --- residential, commercial and industrial --- and by fuel type. The major factors which influence the level of energy consumption are fuel prices and scale factors, such as the number of households and the level of aggregate economic activity. The relationships between energy consumption and the variables which determine it have been estimated for the period 1962 to 1989.

Further development of the model was carried out during 1990. This is described in detail in "The 1990 Econometric Forecast" produced by the Load Forecasts Department. In summary, the major changes were the following.

In the industrial sector model the same two-stage procedure used for the 1989 forecast was applied. The first stage estimates the demand for energy as a whole while in stage two a cost share model is used to disaggregate total energy into the individual fuel types. Last year, this second stage consisted of four fuels -electricity, oil, natural gas and coal - while for the 1990 forecast, oil and natural gas have been combined into a single "liquid fuel".

In the residential sector, the same basic approach has also been used as in last year's forecast except that the electricity usage index was defined in terms of use per housing unit rather than use per household. In addition, the saturation index is used as an explanatory variable in the use equation for electricity so that these two equations must be estimated using three-stage least squares.

The commercial model has undergone more extensive revision. Instead of the two-stage approach used last year, as in the industrial sector model, single equation models are estimated for electricity and liquid fuel demand. The cost share equations were carefully re-examined but, as last year, did not yield reasonable elasticities. This may reflect the limited inter-fuel competition within the sector, recent counter-intuitive trends in the gas market and the ongoing data quality problems in the commercial sector. The simpler approach adopted is considered more appropriate to the energy market structure and data at this time. For the 1990 forecast, a new time series for natural gas consumption was developed using data provided by the natural gas utilities. While it is believed this is an improvement over the previous series, further development is planned for 1991.

EEMO produces energy forecasts to 2015. The economic forecasts used by the model are from the 1990 Long-Term Economic Outlook and the price forecasts are from the November, 1990 Energy Price Trends report.

The electricity demand forecast is tuned to the July 1990 Short-Term Load Forecast. The amount of tuning required this year was much less than has been the case in previous forecasts and was confined to a negative adjustment of 1 TW.h in 1995 applied to the commercial sector forecast.

The forecasts presented below are net of the impact of appliance standards in the residential and commercial sectors. (See Table 1.5.1 for details of these effects).

5.1 Residential Sector

The demand for electricity in the residential sector is modelled in terms of: (a) the demand for energy-using appliances (saturation), and (b) the intensity of use of the appliance stock (usage).

The estimated equation for the aggregate saturation index (ELSAT) is a partial adjustment model of the prices of electricity, oil and income per household. The aggregate use index (ELUSE) is estimated in terms of demand per housing unit with the price of electricity, income per household, cooling degree days and ELSAT as explanatory variables. Because the saturation index is included in the usage equation, the model cannot be estimated using ordinary least squares, so three-stage least squares is used instead. Another change from the 1989 model is that the price of oil is used in the saturation equation in place of the price of natural gas. The aggregate elasticities estimated this year are compared with the 1989 estimates in the following table.

Table 5.1.1: Estimated Price and Income Elasticities in the Residential Sector

	Short-Run		Long-Run	
	1990	1989	1990	1989
Price of Electricity	-0.13	-0.15	-0.51	-0.78
Price of Oil	0.03	N/A	0.16	N/A
Price of Natural Gas	N/A	0.04	N/A	0.15
Income per Household	0.44	0.73	1.04	1.66

The estimated short-run own-price elasticity is very similar to the 1989 result. However, the long-run response of electricity demand to changes in the real price of electricity has been reduced from -0.78 to -0.51. The cross-price effects are unchanged even though the 1990 model includes oil prices whereas the 1989 model used the natural gas price. Both the long-run and short-run income elasticities are reduced compared to the 1989 results. However, this comparison is slightly misleading because last year's model contained a negative time trend which, given the high degree of correlation between income and time, had the effect of reducing the effective income elasticity. Time trends are not included in this year's model.

The forecasts of the saturation and use indexes and the resulting forecast of residential electricity consumption are given in the following table:

Table 5.1.2: Residential Electricity Forecast

	ELSAT*		ELUSE*		Electricity (TW.h)		Total Residential Energy (TW.h)		Market Share (%)	
Year	1989 F/C	1990 F/C	1989 F/C	1990 F/C	1989 F/C	1990 F/C	1989 F/C	1990 F/C	1989 F/C	1990 F/C
1989	113.8	110.9	104.5	113.2	38.7	41.1	121.1	126.6	32.0	32.5
1995	120.8	118.4	103.1	104.2	45.4	45.5	134.5	135.8	33.8	33.5
2000	129.3	126.1	101.2	101.7	51.4	49.9	138.7	139.0	37.1	35.9
2015	162.4	152.3	89.1	100.1	66.3	67.7	148.7	158.7	44.6	42.7

* 1980 = 100

The 1990 forecast of residential electricity demand is 2.1% greater by 2015 than last year's forecast. However, total residential energy demand is 6.7% above the 1989 level by the end of the forecast period resulting in a decline in electricity's market share in 2015 from 44.6% in the 1989 forecast to 42.7% for the current forecast.

The growth rate of residential electricity demand is down sharply compared to last year's forecast in the short term - to 1995 - from 2.7% per year to 1.7% reflecting the higher electricity price forecast. The two forecasts are the same in level terms in 1995 because the 1990 forecast starts from a higher base. By 2015, the real residential price of electricity, including the impact of the GST, is 26% above the level used in the 1989 forecast. However, nearly three-quarters of this increase occurs in the period 1990 to 1995. Over the period 1995 to 2015, the forecast growth rate of 2% a year is very similar to last year's, - 1.9% per year. This is despite the fact that real electricity prices are projected to increase a further 8% by 2015. As all of this increase occurs in the last ten years of the period, the impact on electricity demand is considerably less than the 4% reduction the long-run price elasticity would indicate. In practice, electricity demand is lowered by about 1.6%. Over the same period personal disposable income increases 3.5% which increases load by 3%. In this sector, the 2.1% increase in forecast for 2015 is largely explained by the offsetting changes in electricity prices and GDP.

5.2 Industrial Sector

Electricity demand in the industrial sector is estimated using a two-stage procedure. In the first stage the demand for aggregate energy is estimated as a function of industrial GDP, the price of energy and a lagged dependent variable. The hypothesis of constant returns to scale with respect to GDP was tested and was not rejected. The long-run elasticity of aggregate energy demand with respect to GDP is, therefore, 1. Its short-run value is estimated to be 0.75. The own-price elasticity of total energy is estimated to be -0.03 in the short run and -0.3 in the long-run. If constant returns to scale are not imposed, the own price elasticity for total energy is of the wrong sign.

The second stage consists of a linear logit cost share model which estimates the cost-minimizing mix of fuels. In this year's model three fuel shares were estimated - electricity, coal and 'liquid fuel' which comprises oil and natural gas together. The long-run elasticities are shown in the following table:

Table 5.2.1: Estimated Total Long-Run Elasticities in the Industrial Sector

	Electricity	Liquid Fuel	Coal
Price of Electricity	-0.30	-0.22	-0.43
Price of Liquid Fuel	-0.14	-0.35	-0.05
Price of Coal	-0.13	0.00	-0.08

The forecast assumptions used are shown in Table 5.2.2.

Table 5.2.2: Summary of Forecast Assumptions

Year	Industrial GDP[1]	Growth Rate[2] (%)	Price of Electricity[3]	Growth Rate[2] (%)	Price of Liquid Fuel[4]	Growth Rate[2] (%)
1989	45356	-	26.36	-	6.94	-
1990	44444	-	26.62	-	6.77	-
1995	53318	3.7	29.28	1.9	7.27	1.5
2000	61534	2.9	29.43	0.1	9.26	5.0
2005	69930	2.6	29.58	0.1	10.60	2.7
2010	78299	2.3	31.30	1.1	11.40	1.5
2015	86587	2.0	33.13	1.1	12.04	1.1
Growth Rates*						
1990 - 2015	2.5		0.9		2.1	
1995 - 2015	2.5		0.6		2.6	

[1] Million 1981 $ at factor cost
[2] Average Annual Percentage Change for 5-Year Periods
[3] 1981 $ Per MW.h
[4] 1981 $ Per Equivalent MW.h
* Annual Average Percent Change

The elasticities shown in Table 5.2.1 reflect the combined impact of two effects. The first is the impact of a change in the price of an individual fuel on the aggregate energy price and thereby on the demand for energy as a whole. The second is the impact on relative fuel prices which changes the composition of aggregate energy demand. The negative cross-price elasticities shown in Table 5.2.1 indicate that the former effect tends to dominate in the long run.

Over the period 1990 to 2015 the price of electricity relative to the price of liquid fuels is projected to decline at an average annual rate of about 1.2%. The cost share of electricity is virtually unchanged for the forecast period as a whole. Its quantity share, however, increases from 21.4% in 1989 to 24.5% by 2015.

Examination of the forecasts of the explanatory variables reveals that between 1995 and 2015 industrial GDP growth is 5% faster in this year's forecast. This increases load by 4.4% in 2015. On the other hand, electricity prices increase 15% between 1995 and 2015 which reduces electricity demand by about 1.6%. The fact that the overall forecast is slightly lower than last year's is due partly to the fact that the 1995 base level is lower by about 1 TW.h and partly due to changes in the model.

Table 5.2.3: Market Share Of Electricity In The Industrial Sector

Year	Electricity (TW.h)	Growth Rate[1] (%)	Energy (TW.h)	Growth Rate[1] (%)	Market Share (%)	Cost Share (%)
1989	47.3	-	221.5	-	21.4	50.8
1990	46.2	-	219.2	-	21.1	50.9
1995	56.5	4.1	254.7	3.0	21.6	53.7
2000	65.5	3.0	283.8	2.2	22.7	50.4
2005	73.1	2.2	310.5	1.8	23.5	48.6
2010	80.7	2.0	335.9	1.6	24.0	49.1
2015	88.1	1.8	359.8	1.4	24.5	49.9

[1] Average Annual Percentage Change for 5-Year Periods

5.3 Commercial Sector

A major difficulty with estimating energy demand equations for the commercial sector is the quality of the available energy consumption data. It is widely recognised that, of all the sectors, the data for the commercial sector is the weakest. For this and other reasons[1] the model was changed significantly in 1990. This year's forecast is based on a single equation model which explains electricity demand in terms of the commercial sector electricity price, commercial GDP and a lagged dependent variable.

The own price elasticities of demand are -0.06 in the short run and -0.46 in the long run which are lower than those in last year's model, -0.55 and -0.97 respectively. The corresponding elasticities for GDP are 0.13 and 1.18 which are similar to the 1989 results.

Over the period 1990 to 2015 the price of electricity increases at an annual average rate of 0.5% while GDP grows at 2.8% per year. Given the elasticities, this yields a forecast growth rate of electricity demand of 3.5% per year. Electricity's market share increases over the period from 41.5% to 53.0%. Its cost share, however increases only slightly - from 71.1% to 74.2%.

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[1] See 'The 1990 Econometric Forecast', Load Forecasts Department.

Table 5.3.1: Market Share Of Electricity In The Commercial Sector

Year	Electricity (TW.h)	Growth Rate[1] (%)	Total Energy (TW.h)	Growth Rate[1] (%)	Market Share (%)	Cost Share (%)
1989	46.6	-	111.8	-	41.7	71.1
1990	47.0	-	112.3	-	41.9	73.3
1995	57.1	3.9	144.7	5.2	39.4	71.3
2000	69.2	3.9	162.8	2.4	42.7	69.5
2005	82.9	3.7	177.6	1.8	47.0	70.3
2010	98.1	3.4	196.0	2.0	50.4	72.4
2015	114.9	3.2	217.7	2.1	53.0	74.2

[1] Average Annual Percentage Change for 5-Year Periods

Any comparison between the 1989 and 1990 forecasts is complicated by the fact that the models used in each year are quite different. However, it is possible to see the impact of changes in the forecast assumptions - GDP and energy prices - by simulating this year's model with both sets of inputs. Such a comparison indicates the following. First, commercial GDP is about 9% higher in 2015 in this year's forecast which should ultimately produce a 10.6% increase in electricity demand given the long-run GDP elasticity of 1.18. In fact, the increase in electricity demand due to the new GDP forecast is 6% by 2015. This is due to the pattern of the 1990 GDP forecast being different from last year's.

Secondly, the forecast price of electricity is 15% above last year's level in 2015. The elasticity effect should produce a decrease in electricity demand of 6.9% by 2015. Here again, because the patterns of the two price forecasts are different, the full elasticity effect does not come through by 2015. The actual decline in demand by 2015 due to price is 4.5%. The combined effect of the changes in the GDP and electricity price forecasts is an increase of 1.2% in electricity demand by 2015 in the 1990 forecast. The actual difference between the 1990 and 1989 commercial forecasts is 10.2% indicating that 9% is due to changes in the model and other factors.

5.4. The 1990 EEMO Forecast

The EEMO forecast results project that total residential electricity demand will increase at an average annual rate of 1.9% over the period 1990 to 2015 while total residential energy grows at an average of 0.9% a year and the growth rate of personal disposable income per household averages 1.6% a year.

The commercial sector shows the fastest growth of all the sectors averaging 3.5% per year over the period 1990 to 2015 for electricity demand, 2.6% a year for total energy and 2.8% a year for commercial GDP.

In the industrial sector, electricity growth averages 2.4% a year between 1990 and 2015, while total energy grows more slowly at 1.8% a year and industrial output growth averages 2.4% a year.

In order to derive the Basic Load Forecast from the sum of the three sectoral forecasts, load displacement non-utility generation and non-Hydro electricity sales are subtracted out and other adjustments, mainly line losses, are added on.

Compared to the previous forecast, the level of non-utility generation has been decreased and the imputed level on non-Hydro sales has been increased resulting in the observed increase in the level of the 'adjustments'.

Table 5.4: The 1990 EMMO Forecast

Year	Residential (TW.h)	Commercial (TW.h)	Industrial (TW.h)	Own Generation (TW.h)	Adjustments* (TW.h)	EEMO Basic Electric Energy (TW.h)
1989(A)	41.1	46.6	47.3	6.0	10.9	139.9
1990	41.9	47.0	46.2	6.2	11.0	139.9
1995	45.5	57.1	56.5	6.8	12.9	165.2
2000	49.9	69.2	65.5	7.5	13.8	190.9
2005	55.9	82.9	73.1	7.9	15.4	219.4
2010	61.7	98.1	80.7	8.2	17.7	250.0
2015	67.7	114.9	88.1	8.6	20.3	282.4
Growth Rates**						
1989-1995	1.7	3.4	3.0			2.8
1989-2000	1.8	3.7	3.0			2.9
1989-2010	2.0	3.6	2.6			2.9
1989-2015	1.9	3.5	2.4			2.8
1995-2015	2.0	3.6	2.2			2.7

* Ontario Hydro losses less Ontario electricity not sold by Hydro (excluding own generation).

** Annual Average Percent Change

The EEMO forecast of basic electric energy in 2015 is 282.4 TW.h. This represents an increase of 14.5 TW.h, or 5.4% over the 1989 forecast level. However, most of this increase occurs in the commercial sector which is up 10.2 TW.h in 2015 over the 1989 forecast.

Over the period 1990 to 2015 basic electric energy grows at an annual average rate of 2.8% a year. At the same time Ontario GDP growth averages 2.7% a year and the real price of electricity increased by 0.8% a year. In comparison, the 1989 forecast grew 2.5% driven by a projected growth of GDP of 2.4% between 1990 and 2015 and zero real growth of electricity prices over the period.

While the forecast is higher than last year's in 2015, it is actually lower in the year 2000 by 6.9 TW.h. In this period, the overall GDP growth rate is unchanged from the 1989 forecast but electricity prices have increased significantly - about one half of the 20% real price increase projected by 2015 occurs in the first 5 years of the forecast period.

In the period 2000 to 2015 basic energy growth averages 2.6% a year compared to the 1989 forecast growth rate of 2% a year. Most of this faster growth is coming from the commercial sector.

6.0 NET LOAD IMPACT OF PROGRAM-DRIVEN DEMAND MANAGEMENT

The end-use, econometric and recommended forecasts described earlier in this report are all 'Basic' forecasts of load in Ontario. That is, they are projections of the load that Ontario Hydro would expect to serve as a result of market forces and government regulated efficiency improvement standards. The Primary Load Forecast is derived by subtracting from the 'Basic' Load Forecast the net load impact of program-driven demand management and load displacement generation.

Ontario Hydro's programs for demand management include both changes in rate structure to achieve load-shifting (L-S), such as time-of-use rates, and financial incentives for electrical efficiency improvement (EEI) to reduce load, such as grants or attractive loans. Some of Hydro's programs provide valuable information such as audits and consulting studies specifically to customers. These may also contribute to the net reduction in load without a direct transfer of financial assistance. The estimated net impact of such programs is included in this forecast. Since specific electrical efficiency standards are expected to be introduced in Ontario in the next few years, the net load impact forecast of efficiency improvement programs presented in this section includes a separate analysis netting out the effects of standards.

Ontario Hydro's programs for load displacement non-utility generation (LD-NUG) provide financial assistance to industries wishing to produce electricity for their own consumption, thereby reducing the load Ontario Hydro is required to serve.

It is the Primary Load Forecast minus capacity interruptible loads which determines the Firm Load Forecast used by System Planning.

The net load impact forecasts for EEI, L-S and LD-NUG presented in this section were prepared in October, 1990. As the Short-Term Load Forecast was finalized in July, it was based on earlier information. The differences were not deemed to be sufficiently large to warrant revising the Short-Term Load Forecast.

6.1 Program-Driven Demand Management

The net load impact estimates for program-driven demand management offered by Ontario Hydro consist of the load reduction due to EEI and L-S. In preparing the forecast, the most recent information was reviewed for both types of programs. More details are documented in a separate report entitled "Net Load Impact Forecast of Demand Management Programs".

The short-term (1990-1995) EEI estimates are based on a review of the 1990 Energy Management Branch Business Plan and extensive discussions with representatives from Energy Management Branch. The longer term estimates for 1996 and beyond are based on an in-depth analysis of EEI potential recently undertaken by the Energy Economics Section of the Economics and Forecasts Division, Energy Management Branch and System Planning Division.

The estimates of the impact of L-S programs in the short term (1990-1995) are based on information incorporated in the Energy Management Branch Business Plan as well as the results of a questionnaire on the impact of time-of-use rates distributed to customers. The results of several Ontario Hydro studies which investigate time-of-use rates and the implementation experience of other utilities were used as a basis for the long-term estimates. Further research is planned to assess the response of customers to time-of-use rates.

The net load impact forecast of demand management programs does not yet have an uncertainty range associated with it. Simulation studies suggest that it would not decrease Primary Load Forecast uncertainty relative to Basic Load Forecast uncertainty.

6.2 Electrical Efficiency Improvement Programs

Over the past two years, Ontario Hydro has made considerable progress in planning various demand management initiatives. A number of new programs were added in 1990 and changes have been made to the program portfolio introduced in 1989. The following provides a brief description of these programs and the technologies considered in the long-term analysis on a sector by sector basis. For details of the EEI programs, please refer to the 1990 Energy Management Branch Business Plan.

6.2.1 Program Description by Sector

Residential Sector

Major EEI programs currently underway or in an advanced stage of planning in the residential sector are directed at the following:

- R-2000 Houses
- Heat Pumps
- Renovations
- Water Heating
- Energy-Efficient Lighting
- Energy-Efficient Appliances
- Agricultural Uses

In co-operation with the Ontario Home Builders' Association, Ontario Hydro launched a program for energy-efficient R-2000 homes in early 1990. A $2,000 incentive is offered to home buyers to be applied against the incremental construction cost of a new R-2000 home. A $500 incentive is available for builders to cover additional administrative costs. The incentives offered are expected to result in savings of about 3 KW per house.

An incentive program for heat pumps was launched early this year in the existing housing segment covering air source, ground source and bivalent heat pumps. The incentive package offered ranges from $500 for air source, $1000 for bivalent, to $2000 for ground source heat pumps. A similar incentive program was also initiated in the new housing segment. On average, a ground source or bivalent heat pump will save about 4 KW compared with an electric resistance heating system.

Ontario Hydro distributes energy efficiency information to homeowners on a regular basis. Typical renovation measures which save electricity include energy-efficient windows and doors, basement insulation and other thermal envelope improvement upgrades. An incentive program for energy-efficient windows is currently being planned that will offer financial incentives to homeowners installing "double-glazed, low emissivity, argon-filled" windows in existing and new homes.

To reduce energy consumption for electric water heating, Ontario Hydro has initiated a five-year water heater tune-up program this year after several very successful pilot projects in 1989. The tune-up program for existing homes includes three components: adding a water tank insulation blanket, insulating the pipe and adjusting the thermostat to 60 degrees Celsius. For new water heater installations, a heat trap will also be added. Homeowners with electric water heating will be offered the tune-up free of charge. By 1995, over 500,000 tune-ups are expected to be completed. A special campaign, "April Showers", was launched this year to promote energy-efficient showerheads. Customers were offered a 25% rebate of up to $10 for purchasing flow-restricting showerheads.

Ontario Hydro has recently launched a campaign to promote energy-efficient compact fluorescent light bulbs, which can save about 70% of electricity consumed by a standard incandescent lamp. This promotion offers a cash rebate of $5 for every compact fluorescent bulb purchased. Future programs for lighting will include energy-efficient incandescent light bulbs, which are more widely used in the residential sector.

Following a very successful campaign in 1989, a similar promotion is currently being launched with discount coupons for a wide array of energy-efficient products. These campaigns help raise the awareness and interest of homeowners in energy efficiency. Programs for major appliances are also being considered to encourage homeowners to purchase more energy-efficient refrigerators, freezers, clothes washers and dish washers.

After a successful pilot project early this year, a full-scale Power Saver residential audit program will be launched soon to help homeowners identify EEI opportunities. The campaign aims to reach every household in the province of Ontario. Although this program will provide information rather than incentives, it will lead customers to other incentive-driven programs offered by Ontario Hydro.

In the agricultural segment, current programs have focused on high-efficiency lighting and heat lamps. Other energy efficient measures in farm operations are planned for the coming years. They include energy-efficient sentinel lights, heater sizing, heat exchangers, milk heat reclaimers, water bowls and ventilation improvements.

In the long-term analysis, the energy-efficient technologies considered in the residential sector can be grouped into four categories: thermal envelope improvements in existing houses, new housing thermal envelope upgrades, heating system improvements, energy-efficient appliances and other measures. Existing house thermal envelope improvements include various insulation upgrades (roof, attic, wall and floor), infiltration improvements and door and window improvements. New housing thermal envelope improvements are captured through upgrading new electrically-heated houses from Ontario Building Code (OBC) to the R-2000 standard. Although upgrades of OBC houses to levels less than R-2000 are also desirable, OBC to R-2000 is used in the analysis since it is least difficult to measure. Heating system improvements refer to the replacement of an existing electric furnace with a heat pump system. Other measures include promotion of energy-efficient electric appliances, electric water heater improvements and high-efficiency lighting.

Commercial Sector

In 1990, new initiatives and changes to existing programs were added to the commercial sector program portfolio developed in 1989. Programs offered in 1990 include:

- Energy-Efficient Lighting
- Savings-by-Design
- Occupancy Sensors
- Showerhead Exchange
- Streetlighting
- Individual Metering
- Guaranteed Energy Performance
- Motors

The Lighting program was first offered to commercial customers in 1989. In 1990, financial incentives are available for T8 (32 watt) fluorescent lamp systems using electronic ballasts (new construction), 34 watt fluorescent lamps (existing building retrofits), compact fluorescent lamps, high intensity discharge lamps and various lighting redesign initiatives. The Lighting program is expected to continue to expand to include additional energy saving products. Changes to program design are also anticipated to increase participation of lighting contractors and manufacturers. Program changes made in late October 1990 have raised the upper limit on incentives for efficient lighting redesigns and other lighting initiatives to $500/kW saved from the previous $300/kW. Other changes include a modification of the incentive payment schedule and the transfer of authority for approval and payment to Field Offices for incentives less than $5,000.

The Savings-by-Design program was introduced in 1989, offering incentives for customized demand reductions in commercial buildings. In 1990, the program began operating as an "umbrella program" for the commercial sector. In addition to offering customized incentives for energy efficiency projects in new construction, retrofit and expansion projects, the program also includes the Thermal Cool Storage initiative designed to encourage load shifting in the commercial sector. Additional program changes made in October 1990 include higher incentives (up to $750/kW saved) and incentives for additional prescriptive measures (window film, ground source heat pumps, heat recovery ventilators).

The Occupancy Sensors program was first offered in 1989 to customers in the hospitality segment (hotels/motels). Through the program, financial incentives are offered for demand reductions due to the installation of occupancy sensors to control insuite electric heating and cooling. As a result of recent changes to the program, incentive levels have been increased to $150 per room from $50 per room until the end of 1990.

The Showerhead Exchange program was introduced in 1989 to customers in the multi-residential and hospitality segments. The program is used as a "door opener" to encourage energy efficiency in these commercial segments. Incentives of $10 per showerhead (about $250/kW saved) are offered through the program.

The Streetlighting pilot program launched in 1989 has been expanded in 1990 to cover the entire province. The program offers financial incentives of 25% of the cost to municipalities for conversion to energy-efficient streetlighting.

The Individual Metering program is expected to be approved in 1990, and will offer incentives ($300/kW saved or 75% of cost) to property developers in the multi-residential building segment for the installation of individual metering in electrically-heated apartment buildings and condominiums. The program is expected to take place in early 1991.

The Guaranteed Energy Performance program was approved in 1990. This program is designed to provide a comprehensive total energy approach to efficiency improvement in the commercial sector. Through the program, Ontario Hydro will ask Energy Service Companies to help identify specific opportunities for energy and/or capacity savings. Incentives of up to $750/kW saved are offered through the program.

The Motors program introduced in 1989 offers incentives for the installation of energy-efficient motors in both the commercial and industrial sectors. The program is widely communicated in the commercial sector, particularly to design engineers, specification engineers and original equipment manufacturers. Information on incentives and eligible motors is shown under the Industrial Sector High-Efficiency Motors program.

The Power Saver Audit Program is a computerized audit-based program (XENCAP) offered to commercial sector customers. This information program is used as an identifier program by directing customers to appropriate Ontario Hydro incentive programs based on the results of the audit. Although financial incentives are not offered through this program, the information provided (technology recommendations, consulting study proposals, etc.) may also contribute to a net reduction in load.

In addition to the above programs, a refrigeration initiative is under development for 1991 and is expected to offer incentives to customers in the retail, hospitality and institutional building segments for the installation of efficient refrigeration systems and equipment.

The efficient technologies considered in the long-term analysis consist of lighting, motor and space heating/cooling-related measures. Major lighting technologies include T8 (32 watt) fluorescent lamp systems with electronic ballasts, compact fluorescent lamps and automatic lighting control systems. High-efficiency luminaires were also considered for new commercial buildings. The motor-related measures concentrated primarily on building ventilation systems (energy-efficient motors, building automation systems), and air and water balancing of fan and pump systems, respectively. Space heating/cooling technologies considered include ground source heat pumps, energy-efficient windows and window film, infiltration measures and energy efficient cooling. Other energy-efficient technologies (appliances and water heating improvements) were also considered. Other than high-efficiency luminaires (new buildings only), all of the technologies considered for the commercial sector are applicable in both existing and new buildings. While current programs may not address all of the technologies listed above, it is assumed that they will be incorporated into programs in the long term.

Industrial Sector

The current menu of industrial sector programs for electrical efficiency improvement is unchanged from last year. While no new programs were added in 1990, several changes were made to enhance the programs in early October, 1990. The programs included are:

- Energy-Efficient Lighting
- High-Efficiency Motors
- Accelerated Paybacks
- Power Saver Services

The Energy-Efficient Lighting program described for the commercial sector also applies to industrial customers. The program includes such technologies as energy-efficient fluorescent tubes, compact fluorescent bulbs, lighting redesigns and reflectors for fluorescent lamps in retrofit and renovation lighting projects. The latest program changes raised the upper limit on incentives for high-efficiency lighting redesigns and other lighting initiatives to $500/kW from the previous $300/kW.

The High-Efficiency Motor program offers customers a rebate of $12/hp (minimum $50) for the purchase of high-efficiency rather than standard motors. The program originally was limited to "T-frame" motors in the 1 to 200 horsepower range. The program has now been expanded to include "U-frame" motors and the motor size can now be as high as 500 HP. A flat incentive of $2400 per motor is offered for motors in the 250 to 500 HP range. The program also offers an incentive of $3/hp (minimum $10) to motor distributors who sell high-efficiency motors.

The Accelerated Payback program promotes process-specific efficiency improvements which are not covered by the technology-specific (motors, lighting) programs. The incentive offered is the lesser of:

- the amount required to reduce the simple payback to 18 months; or

- $0.10 per kW.h for the first-year energy savings achieved by the project.

The maximum for each project was originally $300,000. With the latest program changes, the maximum limit is no longer strictly applied. For most projects, the program is expected to accelerate the payback by about two years. The program is available for both retrofit projects and new plant designs. The minimum energy savings were originally required to be 50,000 kW.h per year. This minimum was recently lowered to 10,000 kW.h per year. The technology must be proven with an expected operating life of at least ten years.

The Power Saver Services program offers funding to identify EEI opportunities for process and non-process applications. The program includes the Enermark Power Saver Plan and Consultant Studies. The Power Saver Plan is a computerized energy analysis that identifies basic energy efficiency improvements common to industry in Ontario. The analysis evaluates current energy use and identifies energy-saving opportunities and associated costs, paybacks and available incentives. The computerized audit is offered at no cost to all industrial customers.

For more complex electrical loads, the Consultant Studies portion of the program offers funding for detailed audits to identify opportunities for reducing electricity use during the Ontario Hydro peak period. These audits are performed by consulting engineering firms for customers with electrical load greater than 1 MW. Ontario Hydro will cover 100% of the audit cost up to $50,000. Also included under Consultant Studies is funding up to 50% (maximum of $50,000) toward the cost of feasibility studies by consulting firms for customers who have already identified specific opportunities for reducing electrical load. Funding is only available where studies of this type are not commonly provided free of charge.

Other information programs will increase awareness of efficiency improvement potential for such technologies as high-efficiency motors, motor sizing, variable speed drives, motor-driven equipment and compressed air systems.

The majority of the efficient technologies considered in the long-term analysis are related to motors or motor-driven systems in industrial plants. Energy efficient motors and variable speed drives are the major technologies reviewed in this sector. Other technologies include high-efficiency lighting, energy recovery measures (e.g. heat pumps), energy management measures and a number of industry-specific energy efficient technologies. Industrial sector efficiency improvements are applicable as retrofits and add-ons in existing plants and are also considered for new applications.

6.2.2 The Forecast of Net Load Impact by Sector

Table 6.2.2 presents the net load impact forecast of efficiency improvement programs by sector before netting out the effects of standards. For the purpose of this load forecast, the year 2000 target of 2,000 MW set by the corporation for electrical efficiency improvements is considered to be a feasible outcome, subject to the conditions discussed below. The cumulative impact of electrical efficiency improvement programs by the year 2000 is distributed by sector as follows: 50 percent for the commercial sector; 29 per cent for the residential sector; and 21 per cent for the industrial sector. The impacts of standards on efficiency improvement savings have also been estimated and presented in Table 6.4.1. The EEI forecast net of the impacts of standards is used to determine the Primary Load Forecast.

The net load impact due to efficiency improvement programs forecasted for the short term (1990-1995) is based on an assessment of the estimates contained in the 1990 Energy Management Branch Business Plan, available load impact program monitoring reports, and on discussions with various program specialists within the Energy Management Branch. The savings included here are expected to be net program impacts, that is, excluding free riders and natural conservation, and adjusted to reflect the expected permanence of savings over time. For example, short-term credit is given to a program which accelerates an electrical efficiency improvement that is assumed to occur naturally at a later date in the Load Forecast, but the impact will be decayed in the longer term.

Table 6.2.2 Net Load Impact of Efficiency Improvement Programs by Sector Without Standards (MW)

	COMMERCIAL		RESIDENTIAL		INDUSTRIAL		ALL SECTORS	
Year	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1989	16	16	4	4	16	16	36	36
1990	34	50	14	18	47	63	95	131
1991	49	99	26	44	55	118	130	261
1992	52	151	41	85	55	173	148	409
1993	60	211	43	128	55	228	158	567
1994	63	274	44	172	55	283	162	729
1995	68	342	44	216	55	338	167	896
1996	118	460	54	270	22	360	194	1090
1997	135	595	70	340	15	375	220	1310
1998	135	730	80	420	15	390	230	1540
1999	135	865	80	500	15	405	230	1770
2000	135	1000	80	580	15	420	230	2000
2001	125	1125	70	650	15	435	210	2210
2002	110	1235	50	700	15	450	175	2385
2003	105	1340	40	740	15	465	160	2545
2004	100	1440	30	770	15	480	145	2690
2005	95	1535	30	800	15	495	140	2830
2006	90	1625	30	830	15	510	135	2965
2007	55	1680	30	860	15	525	100	3065
2008	50	1730	30	890	15	540	95	3160
2009	50	1780	30	920	15	555	95	3255
2010	50	1830	30	950	15	570	95	3350
2011	50	1880	30	980	15	585	95	3445
2012	50	1930	30	1010	15	600	95	3540
2013	50	1980	30	1040	15	615	95	3635
2014	50	2030	30	1070	15	630	95	3730
2015	50	2080	30	1100	15	645	95	3825

Source: Energy Economics Section
Economics and Forecasts Division

The forecast of the net load impact of efficiency improvement programs for the long term (1996-2015) is based mainly on two sources. One source is the in-depth sectoral studies of efficiency improvement potential undertaken by the Energy Economics Section of the Economics and Forecasts Division as input to the 1989 Demand/Supply Plan analysis. The second source is a more recent co-operative effort between Energy Management Branch, System Planning Division and Economics and Forecasts Division to estimate the efficiency improvement potential to the year 2000. Through these efforts, the potential and attainable induced EEI in Ontario were updated.

The potential induced EEI refers to the total potential electricity savings available in the market place (equivalent to complete replacement of eligible equipment) that are economic yet require Ontario Hydro intervention to be attractive to customers. This intervention is required to overcome barriers in the market place. Intervention may be in the form of financial incentives or services (e.g. audits). Savings that may be expected to occur in the absence of Ontario Hydro intervention (natural conservation) are not included in the estimates of potential induced EEI. Natural conservation potential is implicit in the Basic Load Forecast. Technologies contributing to the potential induced EEI have a premium life cycle unit energy cost (including program adminstration costs) less than Ontario Hydro's avoided costs. (The premium cost relates to the efficiency-attributed incremental capital and operating cost of the efficient technology relative to the standard technology and not the total cost of the efficient technology.) The technologies usually face one or more significant barriers to penetration and/or typically have a payback period to the customer of more than three years.

In each sector, energy-efficient technologies were matched to end-uses and estimates of costs and savings were derived based on typical applications. The system avoided cost for each technology application was calculated by System Planning Division and uneconomic options were excluded from the calculation of potential induced EEI. The potential induced EEI was then estimated for existing and new stock using the latest estimates for technology savings, technology expected life and eligible markets. The End-Use Load Forecast provided major inputs for the estimation of potential induced EEI, such as energy consumption by end-use, and building and equipment stocks. In the commercial and industrial sectors, the potential was calculated by determining the typical savings of economic technologies expressed as a percentage of the end-use load. In the residential sector, the potential was estimated by considering in detail the net savings of various technologies and their eligible stock over the forecast horizon.

Under the median load growth assumption, the potential induced EEI in Ontario is estimated to be about 6,000 MW by the year 2000. The commercial sector (2,970 MW) and residential sector (2,490 MW) contribute most to the potential induced EEI. The estimate of 520 MW for the industrial sector is incomplete. Additional analysis is required for process-specific technologies. It has been suggested that this estimate could be significantly higher. Compared with last year's forecast, the residential and commercial sectors have higher potential induced EEI. For the residential sector, the new estimate incorporated the final results of the 1000 House Study, which identified more saving potential from thermal envelope measures and heat pumps. Other contributing factors include the latest residential sector load forecast assumptions, the inclusion of the agricultural segment and the addition of new technologies such as compact fluorescent lamps and heat trap for water heaters. For the commercial sector, new technologies that were considered include electronic ballasts in T8 fluorescent lamp systems, ground source heat pumps and energy-efficient windows. Using the latest commercial sector load forecast and refining the methodology and natural EEI estimates also contributed to the increase in the potential induced EEI.

In order to estimate the proportion of the potential induced EEI that is thought to be attainable through efficiency improvement programs, estimates of penetration by the year 2000 were developed by the Energy Management Branch. The penetration rates were estimated using recent Ontario Hydro research studies, program experience of United States utilities, and the actual program experience to date of Ontario Hydro in the market place.

The penetration rates provided by the Energy Management Branch are average rates over the period 1990 to 2000. Commercial sector penetration rates range from 15% to 50%. Higher penetration rates in some segments reflect the fact that potential barriers can be more readily overcome. In the industrial sector, penetration rates for all technologies are about 45%. The estimates for the residential sector are less uniform, ranging from 3% for some thermal envelope technologies to 85% for water heater programs.

The attainable induced EEI was estimated using the estimates of the potential induced EEI and the penetration rate estimates. As mentioned above, the amount of attainable savings will depend on factors such as program design and the type and level of incentives and services.

For the longer term (beyond 2000), the attainable induced EEI is derived from three sources.

One source is the growth in new stock which is eligible for efficiency improvement programs.

A second source is the turnover of existing stock technologies that have not yet turned over by 2000. For example, the existing stock of eligible appliances having a useful life of 15 years would need the time from 1990 to 2005 to complete the replacement cycle.

The third source of potential savings is based on the eligibility of standard technologies that have already undergone one round of replacement. For example, a standard efficiency motor may have been replaced by another standard efficiency motor during the early years of an efficient motor program when the associated program penetration rate was low. If this occurred in 1992, the standard motor used for the retrofit would itself be eligible for replacement by an energy efficient motor in 2002 (assuming useful life of the motor is about ten years). This results in a second opportunity for savings from equipment of this vintage.

The effectiveness of incentives will be determined by the nature of the market and economic barriers facing each type of efficient technology. In general, it has been assumed that higher levels of incentives will help achieve greater penetration of the market. Also, it has been assumed that it will be necessary to pay higher levels of incentives in the early 1990s than currently offered in order to meet the demand management targets set by the Corporation.

In each sector, programs are tailored to meet customer needs. They will be delivered through Ontario Hydro offices and participating municipal utilities to customers throughout Ontario with the extensive involvement of manufacturers, distributors, contractors, consulting engineers, architects, energy management consultants and industry associations.

This forecast also takes into account the potential for double-counting created by the electrical efficiency standards to be implemented in Ontario in the next few years. The standards are expected to affect the efficiency levels for space heating and cooling equipment, building codes, and major appliances such as refrigerators, freezers, dishwashers and clothes washers. These measures will apply mostly to the residential sector and the multi-residential segment in the commercial sector. Their impact is included in the Basic Load Forecast and reduces attainable induced EEI. For details of the efficiency standards in the Basic Load Forecast, please refer to the End-Use Load Forecast Reports.

Residential Sector

The net load impact of electrical efficiency improvements presented here for the residential sector reflects the estimates contained in the Energy Management Business Plan (1990-1995) and the latest revisions made during the budgeting process. Adjustments were made to reflect the expected permanence of net savings over time. In total, the efficiency improvement programs offered in the residential sector are expected to reduce peak load by 205 MW by 1995, a small increase of about 5 MW over the 1989 forecast.

The longer term prospects for the residential sector assume more programs and higher incentives will be offered in order to achieve higher EEI savings. The savings are expected to increase gradually in the initial few years when the programs are being designed and launched. After 1995, the programs are expected to be in high gear.

The cumulative total savings associated with efficiency improvement measures in the residential sector are expected to reach 580 MW by the year 2000. The sector could contribute up to 1,100 MW by the year 2015.

The effects of the upcoming efficiency standards in the residential sector (on appliances, heating systems, building standards, etc.) are also analyzed. Due to more efficient standards, the net load impact of the demand management programs discussed earlier will be reduced by 46 MW by the year 2000. For more details of the total impacts due to standards, please refer to the Residential Sector End-Use Forecast Report.

Commercial Sector

The commercial sector forecast of the net load impact of EEI programs reflects the Energy Management Branch Business Plan estimates in the short term (1990-1995). Adjustments were made to the Business Plan estimates to reflect the expected permanence of net savings over time. The current forecast is 62 MW lower than last year's forecast by 1995. This decrease reflects longer than expected lead times between committed and connected megawatt savings, and delays in program launch dates.

For the longer term, the net load impact in the commercial sector due to efficiency improvement programs is estimated to be 1,000 MW by the year 2000. For 1995 to 2000, the megawatt reductions ramp up quickly to levels consistent with full program implementation and the assumption that a broad menu of programs offering higher financial incentives than current levels is available.

The annual net load impacts of commercial sector EEI programs decline beyond the year 2000, as the existing stock available for retrofit declines (although new stock opportunities continue). By 2015, the net load impact is estimated to be 2,080 MW. This is about 20% higher than last year's forecast of cumulative net load impact by 2015, reflecting the inclusion of additional technologies (electronic ballasts, ground source heat pumps, etc.). The impact of the upcoming efficiency standards on demand management programs in the commercial sector will be about 7 MW by the year 2000. For more details of the total impacts due to standards, please refer to the End-Use Load Forecast Reports.

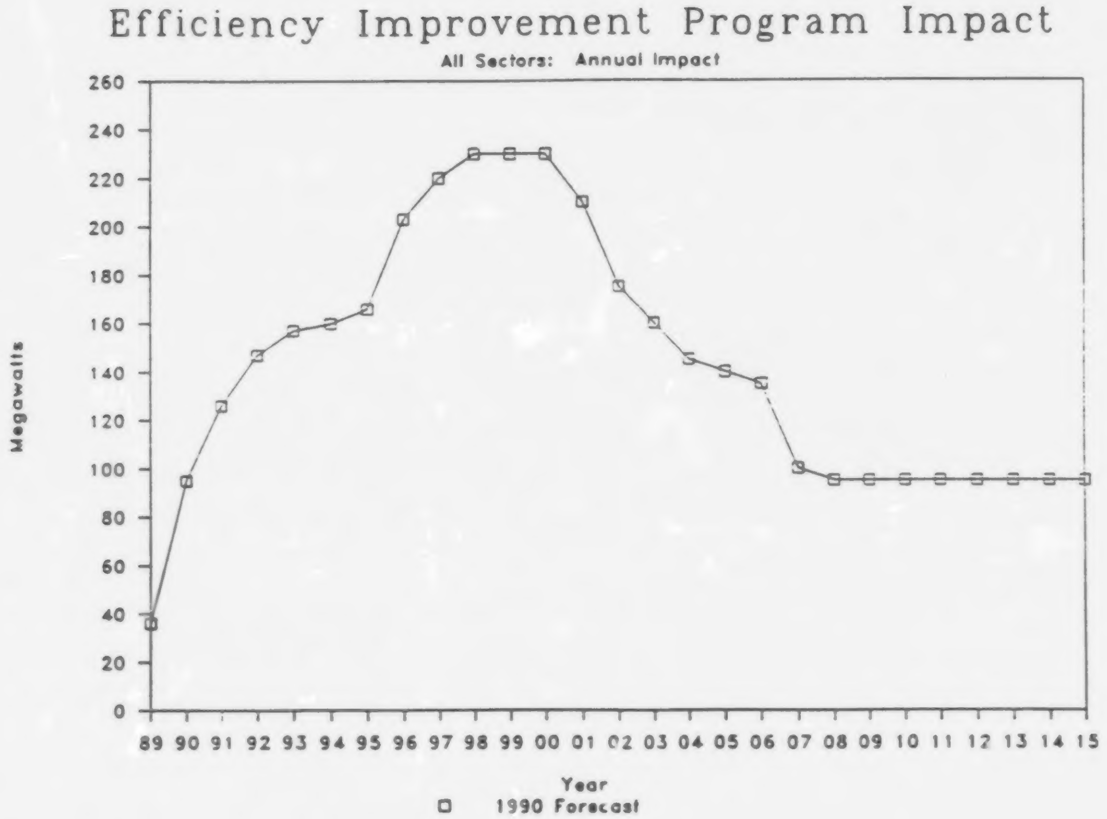
Industrial Sector

The forecast of the net load impact of electrical efficiency improvements in the industrial sector closely reflects the Energy Management Branch Business Plan estimates for the 1990 to 1995 period. Adjustments were made to the Business Plan estimates to reflect the expected permanence of net savings over time. The current forecast exceeds last year's forecast by 147 MW over the 1990 to 1994 period. This reflects higher targets for incentive programs in this year's Business Plan, as well as the inclusion of a greater portion of the service-driven program targets in the forecast.

In the industrial sector, the annual impact is expected to reach its highest level over the period 1991 to 1995. This is based on Energy Management plans which assume that a substantial portion of the savings in the eligible market for existing equipment can be achieved early on. In the industrial sector, there is a large potential for technologies which do not depend on replacement of existing equipment at the end of its useful life (add-on technologies). In addition, the current Business Plan assumes that decisions which normally would be taken to replace existing equipment at the end of its useful life may be accelerated to an earlier date because of Ontario Hydro's incentive and information programs. By 1995, it is assumed that most of the potential savings from existing equipment has been achieved and the additional savings will be largely derived from savings in the new stock. The cumulative impact to the year 2000 is unchanged from last year's forecast at 420 MW. By 2015, a cumulative impact of 645 MW is expected in the industrial sector. This is somewhat lower (55 MW) than last year's forecast.

Current estimates of potential in the industrial sector are incomplete. For example, additional analysis of potential is required for many of the process-specific technologies. While identified potential induced EEI is currently estimated at 520 MW by the year 2000, it has been suggested that this estimate could be significantly higher. Further study has been initiated to more accurately assess the potential for efficiency improvement in the Ontario industrial sector.

Figure 6.2.1



6.3 Load-Shifting Programs

6.3.1 Program Description

Time-of-use (TOU) rates, incentives for Thermal Cool Storage and the recently launched Incentive Program for Load Shifting are the major load-shifting programs currently being offered by Ontario Hydro. Direct control of residential and apartment water heaters is another load-shifting program which may be used in the future if the response to TOU rates is insufficient to achieve Ontario Hydro's load-shifting targets. Other programs may be developed to offer customers additional incentives to shift load from the peak to the off-peak period.

The TOU rate pricing and costing system came into effect January 1, 1989 for all Ontario Hydro direct customers, all large customers of municipal utilities and those municipal utilities which opted for TOU billing. Starting in 1990, TOU rates were offered on a voluntary basis to Ontario Hydro rural retail customers with demand exceeding 1 MW. The new rate structure is being phased in over four years. The revenue collected from demand and energy charges will be gradually altered from the previous 50/50 split to 42/58 by 1992. The capacity/energy split is expected to remain at 42/58 for a period of ten years.

The rate structure includes four TOU periods: winter peak, winter off-peak, summer peak and summer off-peak. Summer is defined as April through September and winter as the remaining months. The peak period in each season is from 7 am to 11 pm Monday to Friday except for public holidays. All other hours are off-peak.

At full implementation, demand charges will be 40% higher during the winter than during the summer and will be applied only to peak period demand. Unit energy costs during the peak period will be 25% higher than during the off-peak in the winter and 60% higher than the off-peak in the summer. Average winter unit energy costs will be 25% higher than average summer unit energy costs.

It is mandatory for all Ontario Hydro direct customers and the large customers of the Municipal Utilities to be billed under TOU rates. The municipal utilities may choose whether to be billed under the TOU rate or the traditional rate structure. As of January 1, 1991, a total of 192 municipal utilities will be billed under TOU rates. Together these customers represent about 97% of the municipal load. Several municipal utilities have recently offered a TOU rate structure to their remaining general service and/or residential customers.

The thermal cool storage program is being offered to large commercial customers in conjunction with TOU rates. The expected load-shifting impacts of both programs are combined in this year's forecast, consistent with the targets in the Energy Management Business Plan. In last year's forecast it was assumed that all of the cool storage savings would occur during the summer period. Recent estimates suggest that a substantial portion of these savings will also occur during the winter, as many large office buildings are cooled year-round.

In late 1990 a new incentive program for load-shifting in the industrial sector was launched. This program is designed to complement and facilitate TOU rates by offering incentives for the installation of additional process-related and/or storage facility equipment to achieve load shifting to the off-peak period. The incentive is based on the lesser of up to $400/kW or the amount required to reduce the simple payback to 18 months or a maximum of $2 million per project. In addition to the capital incentive, the required detailed project evaluation will qualify under the Feasibility Assistance Plan within the Power Saver Services program. The program will target large and direct customers on TOU rates but will not be limited to these customers.

6.3.2 Forecast of Impact of Load-Shifting Programs

The estimates of the impact of load shifting programs for the short-term period to 1995 are based on information incorporated in the Energy Management Branch Business Plan as well as on the results of a questionnaire on the impact of TOU rates distributed to customers by the Economics and Forecasts Division in early 1990. Information provided through the Industrial Sector monitoring activity and an analysis of direct customer billing records has also been considered.

The load-shifting targets for the period 1990 to 1995 contained in the Energy Management Branch business plan indicate a cumulative reduction in winter peak demand of 470 MW. The targets for 1990 include the expected impact of TOU rates and the cool storage program. Starting in 1991, a portion of the impact reflects the targets for the industrial sector incentive program for load-shifting. By 1995 this program is expected to contribute a cumulative winter peak demand reduction of 205 MW. A total of 1.4 MW is included in 1994 and 1995 for direct control of water heaters in the residential sector.

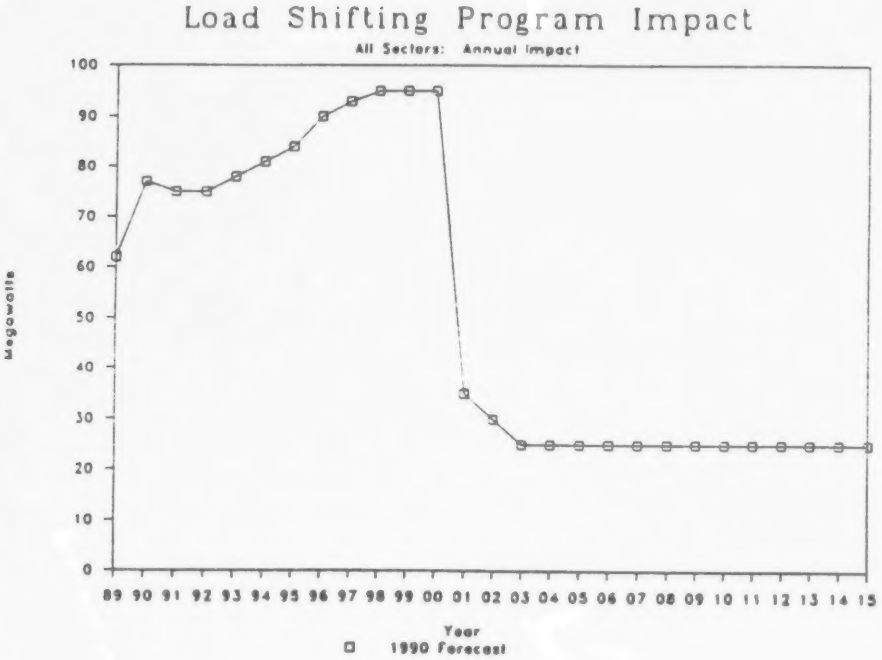
Preliminary results suggest that the respondents to the TOU rate questionnaire will cut their winter peak demand by 37 MW in 1990 in response to TOU rates beyond the 44 MW reduction indicated in last year's questionnaire. The cumulative expected impact for December 1990 is a peak demand reduction of 81 MW. Although these TOU survey results relate to customers representing only a portion of total load, information being gathered by the Energy Management Branch through an analysis of direct customer billing data and through the industrial program monitoring activity is generally consistent with the questionnaire results. This suggests that Ontario Hydro may have some difficulty in achieving its load-shifting targets. Considerable uncertainty about the TOU response for customers who did not complete the questionnaire suggests that more information from billing data and field reports should be collected to better assess the validity of the long-term forecast.

The questionnaire results indicate little incremental load impact due to TOU rates for 1991. This may be because customers are unable to estimate their response to TOU rates accurately beyond the very short term. This appears to have been the experience in last year's questionnaire. Many customers who indicated little incremental impact beyond the first year in response to last year's questionnaire did show a significant incremental effect in the latest questionnaire. The results of future questionnaires will help to determine whether the small incremental impact is realistic. Because of this uncertainty, the questionnaire results for 1991 are not considered reliable and are not reflected in the forecast.

The cumulative impact in this year's forecast over the period 1990 to 1994 is lower than expected last year by 112 MW (386 MW vs. 498 MW). Discouraging results in the commercial sector in response to TOU rates are due to observed limitations for load shifting over a 16-hour peak period. This has contributed to lower targets in the commercial sector.

The long-term impact of load-shifting programs is based on the results of Ontario Hydro studies which investigate customer response to TOU rates and the implementation experience of other utilities and an estimate of the system opportunity for load-shifting. Because of the risks of needle peaking, overshifting and future load shape changes, the target of 1,000 MW in the year 2000 is set below the system opportunity, which is estimated to be about 1200 MW in that year. Further program research is required for programs other than TOU rates to ensure that the year 2000 load-shifting target is achieved. Growth in total system load is expected to result in the opportunity for some additional load-shifting (about 25 MW a year) beyond the year 2000. By 2015, the cumulative impact of load-shifting programs is estimated to be 1,390 MW (See Table 6.4.1).

Figure 6.3.1


Load Shifting Program Impact

All Sectors: Annual Impact

6.4 Forecast of the Net Load Impact of Demand Management Programs

In generating this forecast, it is assumed that the Corporation will pursue an intensive demand management strategy over the next two decades. In particular, a critical assumption is that a comprehensive set of demand management programs backed by significant financial incentives will be in place during the early 1990s.

In deriving the estimates to the year 2000 and beyond, the following assumptions were made:

- by 1992-93, demand management programs will be offered in each of the segments for which potential has been identified;
- by 1992-3, expenditures by Ontario Hydro to induce the take-up of efficient technologies will generally be up to 100% of incremental technology cost and will be available up to full avoided cost as required in order to achieve maximum economic efficiency gain in each segment;
- expenditures in excess of $2 billion (in 1989 dollars) will be made for financial incentives by the year 2000. If Ontario Hydro administrative costs are taken into account, total outlays could be in the order of $3 billion;
- thorough demand management research will provide needed market data;
- sufficient expenditure on program evaluation will be incurred to assess net program impact objectively;

- TOU rates will be widely offered to the customers served by Ontario Hydro and the Municipal utilities. Where TOU rates are not available directly to the customers, load shifting technologies will be promoted to achieve an equivalent impact;

- the market infrastructure (contractors, builders, architects, etc.) and institutional environment (eg, municipal electric utilities) will be in place to permit gearing up of full-scale programs; and

- any other major financial, informational and institutional barriers will be overcome during program design and implementation.

Table 6.4.1 presents the net impact of demand management programs after taking the effects of standards, included in the Basic Load Forecast, into consideration. By the year 2000, the Basic Load Forecast will be reduced by 2,947 MW, of which 1,947 MW will be from efficiency improvement programs and 1,000 MW from load shifting programs. By 2015, the net load impact of demand management programs is expected to be about 5,100 MW. The efficiency improvement and load-shifting programs are expected to contribute 3,710 MW and 1,390 MW respectively.

In order to translate the peak megawatt savings associated with efficiency improvement programs into an annual terawatt hour per year reduction, the following estimated load factors are used: 50 per cent for the residential sector; 65 per cent for the commercial sector; and 75 per cent for the industrial sector. Table 6.4.2 shows the net annual terawatt hour reduction based on the above load factors.

In the case of time-of-use rates, it is assumed that the impact is purely one of load shifting and that there will be no increase or reduction in annual TW.h. Early indications suggest that there may be an overall reduction in energy use in response to time-of-use rates, but it is too early to determine this with confidence. Further research will be required to clarify whether customer response in peak periods is exactly offset in off-peak periods. It will take several years at least to assess this for Ontario Hydro's time-of-use rate structure.

Figure 6.4.1

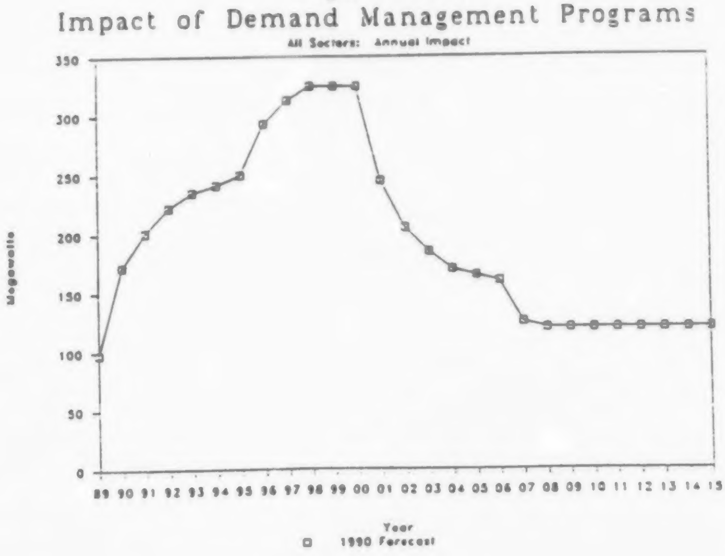


Table 6.4.1 Net Load Impact of Demand Management Programs With Standards (MW)

	Impact of Standards On Efficiency Improvements		Reductions from Basic Load Forecast					
			Efficiency Improvements		Load Shifting		Total	
Year	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1989	0	0	36	36	62	62	98	98
1990	0	0	95	131	77	139	172	270
1991	0	0	130	261	75	214	205	475
1992	1	1	147	408	75	289	222	697
1993	2	3	156	564	78	367	234	931
1994	5	8	157	721	81	448	238	1169
1995	6	14	161	882	84	532	245	1407
1996	7	21	187	1069	90	622	277	1691
1997	7	28	213	1282	93	715	306	1997
1998	8	36	222	1504	95	810	317	2314
1999	8	44	222	1726	95	905	317	2631
2000	9	53	221	1947	95	1000	316	2947
2001	8	61	202	2149	35	1035	237	3184
2002	6	67	169	2318	30	1065	199	3383
2003	5	72	155	2473	25	1090	180	3563
2004	4	76	141	2614	25	1115	166	3729
2005	4	80	136	2750	25	1140	161	3890
2006	3	83	132	2882	25	1165	157	4047
2007	4	87	96	2978	25	1190	121	4168
2008	3	90	92	3070	25	1215	117	4285
2009	4	94	91	3161	25	1240	116	4401
2010	3	97	92	3253	25	1265	117	4518
2011	4	101	91	3344	25	1290	116	4634
2012	3	104	92	3436	25	1315	117	4751
2013	4	108	91	3527	25	1340	116	4867
2014	3	111	92	3619	25	1365	117	4984
2015	4	115	91	3710	25	1390	116	5100

Source: Energy Economics Section
Economics and Forecasts Division

Table 6.4.2: Annual TW.h Reduction Efficiency Improvement Programs

Year	Per Year	Cumulative
1989	0.053	0.053
1990	0.528	0.581
1991	0.713	1.295
1992	0.770	2.065
1993	0.787	2.852
1994	0.815	3.668
1995	0.846	4.513
1996	1.298	5.812
1997	1.121	6.932
1998	1.214	8.146
1999	1.225	9.371
2000	1.247	10.618
2001	1.111	11.728
2002	0.926	12.655
2003	0.835	13.490
2004	0.814	14.304
2005	0.705	15.008
2006	0.719	15.727
2007	0.603	16.331
2008	0.540	16.871
2009	0.434	17.305
2010	0.481	17.786
2011	0.481	18.267
2012	0.532	18.799
1013	0.429	19.228
2014	0.481	19.709
2015	0.481	20.189

6.5 Load Displacement Non-Utility Generation Forecast

Non-Utility generation (or NUG) is electrical generation owned and operated in Ontario by producers other than Ontario Hydro. Non-utility generators include private and municipal utilities, and private power producers. The electricity they generate may be either purchased outright by Hydro for distribution to its customers, or else used to meet the producer's own electricity needs.

Non-utility generation which is sold to Hydro is known as "purchase" generation. The NUG generators involved are interconnected with the province-wide transmission and distribution network. Like purchases from other utilities, purchased generation is considered to be a supply option and is not investigated further here.

On the other hand, non-utility generation which supplies electricity to meet the producer's own needs or is directly purchased by a customer other than Hydro is referred to as "load displacement" generation. It is so termed because such generation displaces load which Hydro would otherwise have been responsible for supplying.

The Non-Utility Generation Division has forecasted that 2107 MW of new non-utility generation capacity is expected to be in operation by the end of the year 2000. By 2015, 3319 MW of new generation capacity is expected. This forecast was based on the attainable potential for small hydro, cogeneration, and other thermal generation in Ontario assuming 1990 Hydro purchase rates, forecasted gas contract prices, equipment costs, and a minimum internal after tax rate of return of 25%. The forecast also accounts for the retirement of NUG facilities. NUG retirements are subtracted from new additions to yield the growth. Energy from NUG facilities was based on a capacity factor of 65% for hydraulic facilities, 80% for cogeneration, and 75% for other thermal facilities.

Based on currently identified NUG projects, about 25% of the new generation capacity is expected to be used for load displacement in the period to 2000. The remainder is expected to be purchase generation. In the long term (beyond the year 2000), this proportion is about 23%. The reduction in load displacement from last year's NUG Plan is due in part to the fact that future generation will also be obtained from third party developments like the Boise Cascade/ICG project in Fort Frances which is treated as purchase generation.

There currently exists over 1200 MW of load displacement generation that has been developed in response to normal market forces. Without Hydro's programs, load displacement NUGs would have been expected to experience a 'natural' growth in future. To account for this component, a portion of the load displacement forecast is classified as natural. The remainder of the load displacement forecast is referred to as incentive or program-driven load displacement. It is the net load displacement generation that is induced by Ontario Hydro's NUG programs and is similar to the net load impact of program-driven demand management.

The natural load displacement forecast was based on a linear projection of past growth minus forecasted retirements. By the end of the year 2000, it is forecasted that a total of 252 MW of NUG growth would have occurred anyway. The natural component of load displacement NUGs is subtracted out as part of the adjustment from Total Ontario Electricity Demand to the Basic Load Forecast.

The difference between the total load displacement forecast and the natural load displacement forecast is referred to as the program-driven component. By the end of the year 2000, it is forecasted that 262 MW of new program-driven NUG additions are expected. The program-driven load displacement generation is subtracted from the Basic Load Forecast.

Before the natural and program-driven components of load displacement non-utility generation can be implemented in the load forecast process, two other factors must be accounted for; namely, dependable capacity and demand displacement. Factoring in dependable capacity reduces the total forecast of NUG capacity available to account for such contingencies as outages and low river flows. The dependable capacity for all non-utility generation is considered to be 90% of installed capacity.

Factoring in demand displacement increases NUG load displacement capacity. Similarly to demand management options, load displacement NUGs generally reduce

Ontario Hydro's transmission line losses. To credit load displacement generators for this benefit, a demand displacement factor of 105% is assumed.

Compared to the 1989 NUG Plan, the 1990 NUG Plan in total represents an increase from 1635 MW to 2107 MW. Over the period from 1990-95, total values are up only marginally. After 1995, there are larger increases in yearly totals, mostly due to the forecast increased feasibility of cogeneration.

Load displacement values are down in all years due to the forecast increase in third-party arrangements for development of cogeneration, which translates into purchase rather than load displacement generation.

Retirements, which affect natural load displacement only, have been reduced from 17 MW/year assumed in the 1989 NUG Plan to 2 MW/year in 1990. This change was a result of a review of historical retirements over the last 50 years and was included in the 1989 load forecast.

Program driven load displacement is assumed to have a project life of at least thirty years (30), which places any of these retirements outside of the time frame of the Plan.

The forecast details are summarized in Tables 6.5.1, 6.5.2 and 6.5.3.

Table 6.5.1: Load Displacement Non-Utility Generation - Natural Load Displacement Forecast

Year	Additions MW	Cumulative Net Additions MW	Cumulative Dependable MW	Yearly Energy GW.h
1990	51	49	36	276
1991	1	48	35	269
1992	25	71	56	431
1993	25	94	78	592
1994	20	112	95	718
1995	20	130	112	844
1996	20	148	129	970
1997	25	171	151	1131
1998	25	194	173	1293
1999	20	212	190	1419
2000	20	230	207	1545
2001	14	242	218	1629
2002	14	254	229	1713
2003	14	266	241	1797
2004	14	278	252	1881
2005	12	288	261	1951
2006	12	298	271	2021
2007	12	308	280	2091
2008	12	318	290	2162
2009	12	328	299	2232
2010	12	338	309	2302
2011	12	348	310	2372
2012	12	358	328	2442
2013	12	368	337	2512
2014	12	378	347	2582
2015	12	388	356	2652

Notes:
(1) Net additions reflect natural retirement.
(2) Dependable capacity calculated as follows:

- (i) 70% of rated capacity for hydraulic facilities
- (ii) 90% of rated capacity for thermal facilities
- (iii) All faciliites increased by 105% due to line loss savings credit.

(3) Energy based on 80% load factor for thermal and 65% for hydraulic.
(4) 1990 values based on expected in-service dates.

Table 6.5.2: Load Displacement Non-Utility Generation - Program Driven Load Displacement Forecast

Year	Additions MW	Cumulative Net Additions MW	Cumulative Dependable MW	Yearly Energy GW.h
1990	0	62	59	343
1991	7	69	65	484
1992	20	89	84	624
1993	30	119	112	834
1994	22	141	133	988
1995	20	161	152	1,128
1996	19	180	170	1,261
1997	21	201	190	1,409
1998	21	222	210	1,556
1999	20	242	229	1,696
2000	20	262	248	1,836
2001	4	266	251	1,864
2002	4	270	255	1,892
2003	4	274	259	1,920
2004	3	277	262	1,941
2005	3	280	265	1,962
2006	3	283	267	1,983
2007	3	286	270	2,004
2008	3	289	273	2,025
2009	3	292	276	2,046
2010	3	295	279	2,067
2011	3	298	282	2,088
2012	3	301	284	2,109
2013	3	304	287	2,130
2014	3	307	290	2,151
2015	3	310	293	2,172

Notes:
(1) Dependable capacity calculated as in Table 6.5.1
(2) Energy based on 80% load factor for thermal and 65% for hydraulic
(3) 1989 values based on expected in-service dates
(4) Program Driven is the difference between natural and total load displacement

Table 6.5.3: Load Displacement Non-Utility Generation - Total Load Displacement Forecast

Year	Additions MW	Cumulative Net Additions MW	Cumulative Dependable MW	Yearly Energy GW.h
1990	51	111	94	620
1991	8	117	100	753
1992	45	160	140	1,054
1993	55	213	191	1,426
1994	42	253	228	1,706
1995	50	291	264	1,972
1996	39	329	299	2,232
1997	46	372	341	2,540
1998	46	416	382	2,848
1999	40	454	410	3,115
2000	40	492	454	3,381
2001	18	508	469	3,493
2002	18	524	484	3,605
2003	18	540	500	3,717
2004	17	555	514	3,822
2005	15	568	526	3,914
2006	15	581	538	4,005
2007	15	594	551	4,096
2008	15	607	563	4,187
2009	15	620	575	4,278
2010	15	633	587	4,369
2011	15	646	600	4,460
2012	15	659	612	4,551
2013	15	672	624	4,642
2014	15	685	637	4,733
2015	15	698	649	4,825

Notes:
(1) Dependable capacity calculated as in Table 6.5.1
(2) Energy based on 80% load factor for thermal and 65% for hydraulic
(3) 1989 values based on expected in-service dates
(4) At-Will energy not included

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	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1990													
20 Min PEAK MW	23346	22703	22238	19907	18595	19825	20154	20177	18862	19744	22047	23874	20956.0
1 hr PEAK MW	23097	22545	22038	19734	18441	19691	20032	20056	18689	19518	21831	23704	20781.4
Energy Gwh	13540	12251	12738	11014	10707	10881	11358	11305	10668	11411	12199	13351	141423.0
Energy Av MW	18199	18230	17121	15297	14392	15112	15266	15195	14817	15337	16943	17945	16144.2
*L.F. %	78.8	80.9	77.7	77.5	78.0	76.7	76.2	75.8	79.3	78.6	77.6	75.7	77.7
1991													
20 Min PEAK MW	24354	23106	22675	20034	18753	19867	20185	20225	18931	19885	22216	24094	21193.8
1 hr PEAK MW	24091	22948	22471	19859	18600	19736	20066	20107	18759	19658	22001	23922	21018.2
Energy Gwh	14176	12551	13016	11129	10829	10947	11411	11363	10736	11526	12330	13503	143516.0
Energy Av MW	19053	18677	17494	15456	14555	15203	15337	15274	14912	15492	17125	18149	16383.1
*L.F. %	79.1	81.4	77.9	77.8	78.3	77.0	76.4	76.0	79.5	78.8	77.8	75.9	77.9
1992													
20 Min PEAK MW	25236	23909	23452	20684	19395	20568	20964	21002	19642	20557	23007	25150	21963.9
1 hr PEAK MW	24959	23743	23236	20500	19234	20429	20838	20877	19461	20317	22781	24968	21778.7
Energy Gwh	14701	13470	13487	11515	11212	11348	11874	11820	11161	11943	12790	14116	149436.0
Energy Av MW	19760	19354	18127	15992	15069	15761	15960	15887	15501	16052	17764	18973	17012.3
*L.F. %	79.2	81.5	78.0	78.0	78.3	77.1	76.6	76.1	79.7	79.0	78.0	76.0	78.1
1993													
20 Min PEAK MW	25836	24483	23990	21121	19796	20972	21402	21428	20058	20965	23491	25711	22437.9
1 hr PEAK MW	25551	24313	23767	20933	19631	20831	21274	21301	19874	20720	23259	25525	22248.4
Energy Gwh	15097	13355	13824	11782	11459	11588	12134	12077	11392	12192	13071	14444	152415.0
Energy Av MW	20292	19873	18581	16364	15401	16094	16309	16232	15822	16387	18155	19414	17399.0
*L.F. %	79.4	81.7	78.2	78.2	78.5	77.3	76.7	76.2	79.6	79.1	78.1	76.1	78.2
1994													
20 Min PEAK MW	26358	24962	24454	21481	20152	21349	21798	21826	20422	21345	23959	26288	22866.1
1 hr PEAK MW	26065	24789	24224	21288	19983	21206	21669	21698	20234	21093	23722	26097	22672.3
Energy Gwh	15439	13658	14127	12024	11694	11828	12395	12337	11637	12459	13379	14814	155790.0
Energy Av MW	20751	20324	18988	16699	15718	16428	16659	16582	16162	16746	18582	19911	17784.2
*L.F. %	79.6	82.0	78.4	78.4	78.7	77.5	76.9	76.4	79.9	79.4	78.3	76.3	78.4

* Load Factor based on 1-Hour Peak

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	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1995													
20 Min PEAK MW	26972	25527	24998	21909	20567	21784	22251	22339	20837	21774	24486	27087	23377.7
1 hr PEAK MW	26671	25349	24761	21710	20393	21637	22120	22207	20644	21514	24242	26889	23178.2
Energy Gwh	15845	14014	14484	12307	11971	12106	12694	12630	11911	12756	13717	15310	159745.0
Energy Av MW	21297	20855	19467	17094	16090	16814	17061	16975	16544	17146	19051	20578	18235.7
*L.F. %	79.8	82.3	78.6	78.7	78.9	77.7	77.1	76.4	80.1	79.7	78.6	76.5	78.7
1996													
20 Min PEAK MW	27579	26098	25556	22381	20924	22184	22668	22763	21212	22262	25072	27768	23872.2
1 hr PEAK MW	27269	25915	25312	22175	20745	22032	22533	22627	21012	21993	24820	27563	23666.3
Energy Gwh	16196	14843	14802	12568	12223	12369	12974	12911	12178	13044	14043	15688	163841.3
Energy Av MW	21769	22088	19896	17455	16429	17179	17438	17354	16914	17533	19504	21087	18703.3
*L.F. %	79.8	85.2	78.6	78.7	79.2	78.0	77.4	76.7	80.5	79.7	78.6	76.5	79.0
1997 ****													
20 Min PEAK MW	28241	26682	26094	22795	21294	22566	23041	23114	21500	22530	25382	28113	24279.3
1 hr PEAK MW	27920	26492	25842	22583	21109	22410	22902	22974	21296	22255	25124	27904	24067.6
Energy Gwh	16609	14676	15140	12829	12471	12610	13216	13139	12377	13237	14246	15909	166460.8
Energy Av MW	22324	21839	20349	17819	16762	17515	17764	17660	17190	17791	19787	21383	19002.4
*L.F. %	80.0	82.4	78.7	78.9	79.4	78.2	77.6	76.9	80.7	79.9	78.8	76.6	79.0
1998 ****													
20 Min PEAK MW	28596	26999	26397	23020	21513	22812	23296	23370	21718	22741	25654	28443	24546.7
1 hr PEAK MW	28268	26806	26139	22804	21324	22653	23153	23227	21509	22459	25390	28229	24330.2
Energy Gwh	16857	14895	15361	13006	12653	12800	13418	13342	12567	13432	14471	16170	168971.1
Energy Av MW	22657	22165	20647	18064	17006	17778	18035	17933	17454	18053	20098	21734	19288.9
*L.F. %	80.2	82.7	79.0	79.2	79.8	78.5	77.9	77.2	81.1	80.4	79.2	77.0	79.3
1999 ****													
20 Min PEAK MW	28937	27303	26684	23231	21718	23043	23534	23607	21918	22929	25900	28744	24795.6
1 hr PEAK MW	28603	27105	26421	23010	21525	22880	23389	23461	21704	22641	25630	28525	24574.4
Energy Gwh	17133	15131	15592	13184	12829	12977	13601	13519	12727	13587	14644	16367	171292.0
Energy Av MW	23028	22517	20957	18311	17243	18024	18281	18170	17677	18262	20339	21999	19553.9
*L.F. %	80.5	83.1	79.3	79.6	80.1	78.8	78.2	77.4	81.4	80.7	79.4	77.1	79.6

* Load Factor based on 1-Hour Peak

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BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2000 ****													
20 Min PEAK MW	29256	27591	26963	23439	21929	23284	23789	23867	22143	23149	26186	29096	25057.7
1 hr PEAK MW	28914	27389	26694	23214	21732	23117	23641	23717	21925	22856	25911	28873	24832.0
Energy Gwh	17383	15327	15819	13376	13026	13179	13807	13728	12927	13795	14876	16631	173876.0
Energy Av MW	23365	22808	21262	18578	17508	18304	18558	18452	17955	18542	20661	22354	19848.9
*L.F. %	80.8	83.3	79.7	80.0	80.6	79.2	78.5	77.8	81.9	81.1	79.7	77.4	79.9
2001 **													
20 Min PEAK MW	29642	27947	27311	23718	22225	23619	24145	24233	22481	23474	26586	29565	25412.3
1 hr PEAK MW	29293	27741	27037	23488	22024	23449	23993	24080	22258	23174	26304	29337	25181.6
Energy Gwh	17683	15616	16080	13577	13239	13403	14053	13969	13152	14012	15124	16920	176827.4
Energy Av MW	23767	23238	21613	18857	17794	18616	18888	18775	18267	18834	21005	22742	20185.8
*L.F. %	81.1	83.8	79.9	80.3	80.8	79.4	78.7	78.0	82.1	81.3	79.9	77.5	80.2
2002 **													
20 Min PEAK MW	30126	28397	27751	24083	22598	24025	24562	24654	22866	23845	27027	30074	25833.9
1 hr PEAK MW	29769	28187	27471	23848	22393	23851	24407	24498	22638	23538	26740	29841	25598.3
Energy Gwh	17996	15892	16363	13809	13477	13646	14308	14224	13391	14257	15394	17229	179985.0
Energy Av MW	24188	23649	21993	19179	18114	18953	19231	19118	18599	19162	21380	23157	20546.2
*L.F. %	81.3	83.9	80.1	80.4	80.9	79.5	78.8	78.0	82.2	81.4	80.0	77.6	80.3
2003 **													
20 Min PEAK MW	30650	28886	28228	24483	22994	24452	25002	25097	23271	24246	27499	30614	26285.3
1 hr PEAK MW	30285	28670	27941	24242	22784	24275	24844	24938	23039	23933	27205	30375	26044.3
Energy Gwh	18327	16185	16661	14056	13726	13900	14574	14489	13641	14513	15678	17551	183301.2
Energy Av MW	24634	24084	22393	19523	18449	19306	19589	19475	18946	19507	21775	23590	20924.8
*L.F. %	81.3	84.0	80.1	80.5	81.0	79.5	78.8	78.1	82.2	81.5	80.0	77.7	80.3
2004 **													
20 Min PEAK MW	31203	29403	28733	24909	23408	24897	25459	25555	23692	24669	27992	31174	26757.8
1 hr PEAK MW	30831	29183	28440	24664	23193	24715	25298	25393	23455	24349	27692	30931	26512.0
Energy Gwh	18671	16447	16969	14312	13982	14159	14846	14760	13895	14778	15969	17880	186669.7
Energy Av MW	25095	24475	22808	19878	18793	19666	19955	19838	19298	19864	22179	24032	21309.3
*L.F. %	81.4	83.9	80.2	80.6	81.0	79.6	78.9	78.1	82.3	81.6	80.1	77.7	80.4

* Load Factor based on 1-Hour Peak

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BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2005 **													
20 Min PEAK MW	31778	29941	29257	25353	23837	25358	25934	26033	24131	25115	28510	31761	27250.5
1 hr PEAK MW	31398	29716	28958	25102	23618	25173	25769	25867	23888	24788	28204	31513	26999.4
Energy Gwh	19026	16801	17291	14580	14248	14431	15132	15044	14162	15058	16276	18226	190274.5
Energy Av MW	25573	25002	23241	20250	19150	20043	20338	20221	19670	20239	22605	24497	21720.8
*L.F. %	81.4	84.1	80.3	80.7	81.1	79.6	78.9	78.2	82.3	81.6	80.1	77.7	80.4
2006 **													
20 Min PEAK MW	32377	30500	29800	25814	24278	25830	26417	26517	24573	25564	29029	32347	27753.9
1 hr PEAK MW	31988	30270	29495	25557	24054	25641	26248	26348	24326	25231	28716	32094	27497.4
Energy Gwh	19388	17121	17616	14850	14516	14703	15415	15326	14427	15334	16576	18566	193837.0
Energy Av MW	26059	25477	23677	20625	19511	20420	20720	20599	20037	20610	23023	24954	22127.5
*L.F. %	81.5	84.2	80.3	80.7	81.1	79.6	78.9	78.2	82.4	81.7	80.2	77.8	80.5
2007													
20 Min PEAK MW	32982	31073	30367	26302	24752	26345	26951	27060	25081	26087	29635	33033	28305.7
1 hr PEAK MW	32585	30838	30055	26040	24523	26152	26779	26886	24828	25747	29315	32774	28043.5
Energy Gwh	19773	17463	17970	15149	14816	15009	15742	15653	14738	15663	16938	18975	197888.0
Energy Av MW	26576	25987	24153	21040	19914	20846	21158	21039	20469	21053	23526	25504	22590.0
*L.F. %	81.6	84.3	80.4	80.8	81.2	79.7	79.0	78.3	82.4	81.8	80.2	77.8	80.6
2008 **													
20 Min PEAK MW	33675	31717	30989	26832	25257	26877	27490	27596	25571	26579	30192	33652	28868.9
1 hr PEAK MW	33270	31478	30671	26565	25023	26680	27314	27419	25313	26232	29866	33387	28601.5
Energy Gwh	20168	17760	18322	15440	15102	15297	16039	15947	15012	15945	17241	19312	201584.9
Energy Av MW	27108	26429	24626	21444	20299	21246	21558	21434	20850	21432	23946	25957	23012.0
*L.F. %	81.5	84.0	80.3	80.7	81.1	79.6	78.9	78.2	82.4	81.7	80.2	77.7	80.5
2009 **													
20 Min PEAK MW	34309	32317	31578	27341	25750	27407	28035	28147	26084	27103	30794	34329	29432.8
1 hr PEAK MW	33896	32073	31253	27069	25512	27206	27856	27966	25820	26748	30462	34059	29160.0
Energy Gwh	20564	18160	18684	15746	15409	15611	16369	16276	15324	16273	17599	19714	205727.5
Energy Av MW	27640	27023	25112	21869	20712	21681	22001	21877	21283	21873	24443	26497	23484.9
*L.F. %	81.5	84.3	80.4	80.8	81.2	79.7	79.0	78.2	82.4	81.8	80.2	77.8	80.5

* Load Factor based on 1-Hour Peak

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2010 **													
20 Min PEAK MW	34997	32961	32204	27877	26263	27951	28590	28701	26594	27619	31382	34985	30010.5
1 hr PEAK MW	34575	32711	31872	27599	26020	27746	28407	28517	26325	27257	31043	34710	29732.0
Energy Gwh	20968	18516	19047	16052	15712	15914	16686	16591	15618	16580	17929	20085	209697.4
Energy Av MW	28183	27553	25601	22294	21118	22103	22427	22300	21691	22285	24901	26996	23938.1
*L.F. %	81.5	84.2	80.3	80.8	81.2	79.7	78.9	78.2	82.4	81.8	80.2	77.8	80.5
2011													
20 Min PEAK MW	35670	33596	32827	28416	26783	28507	29162	29279	27131	28168	32012	35692	30603.6
1 hr PEAK MW	35240	33341	32488	28132	26535	28298	28975	29091	26857	27799	31665	35411	30319.3
Energy Gwh	21383	18884	19427	16373	16032	16239	17027	16932	15941	16921	18300	20501	213960.1
Energy Av MW	28740	28102	26112	22740	21548	22554	22886	22759	22140	22743	25417	27555	24424.7
*L.F. %	81.6	84.3	80.4	80.8	81.2	79.7	79.0	78.2	82.4	81.8	80.3	77.8	80.6
2012 **													
20 Min PEAK MW	36389	34268	33481	28976	27320	29077	29742	29858	27665	28709	32625	36376	31207
1 hr PEAK MW	35950	34009	33135	28686	27067	28864	29551	29666	27385	28332	32272	36090	30917
Energy Gwh	21806	19202	19807	16691	16347	16557	17359	17260	16249	17242	18646	20888	218054
Energy Av MW	29309	28574	26622	23182	21972	22996	23332	23199	22568	23175	25897	28075	24892.0
*L.F. %	81.5	84.0	80.3	80.8	81.2	79.7	79.0	78.2	82.4	81.8	80.2	77.8	80.5
2013 **													
20 Min PEAK MW	37075	34903	34091	29493	27809	29590	30259	30368	28128	29170	33145	36949	31748.3
1 hr PEAK MW	36627	34639	33739	29198	27551	29373	30065	30174	27844	28787	32786	36658	31453.4
Energy Gwh	22136	19550	20112	16949	16608	16823	17640	17543	16518	17523	18954	21237	221592.6
Energy Av MW	29753	29092	27032	23541	22323	23365	23710	23579	22941	23553	26326	28544	25296.0
*L.F. %	81.2	84.0	80.1	80.6	81.0	79.5	78.9	78.1	82.4	81.8	80.3	77.9	80.4
2014 **													
20 Min PEAK MW	37664	35460	34638	29965	28267	30083	30767	30882	28605	29658	33706	37582	32273.0
1 hr PEAK MW	37208	35191	34280	29665	28005	29862	30570	30684	28315	29268	33341	37286	31972.8
Energy Gwh	22511	19882	20454	17238	16897	17117	17948	17852	16808	17829	19287	21611	225435.0
Energy Av MW	30256	29586	27492	23942	22711	23774	24124	23994	23344	23964	26788	29048	25734.6
*L.F. %	81.3	84.1	80.2	80.7	81.1	79.6	78.9	78.2	82.4	81.9	80.3	77.9	80.5

* Load Factor based on 1-Hour Peak

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2015 **													
20 Min PEAK MW	38310	36066	35229	30474	28757	30605	31301	31418	29102	30161	34283	38229	32828.1
1 hr PEAK MW	37847	35792	34865	30168	28490	30380	31101	31217	28807	29764	33911	37927	32522.6
Energy Gwh	22946	20260	20834	17551	17201	17419	18259	18153	17086	18113	19588	21941	229350.3
Energy Av MW	30841	30148	28003	24376	23120	24194	24541	24399	23731	24345	27205	29491	26181.5
*L.F. %	81.5	84.2	80.3	80.8	81.2	79.6	78.9	78.2	82.4	81.8	80.2	77.8	80.5

* Load Factor based on 1-Hour Peak

NOTE
For years marked with ** the growth of Basic Load over the course of the year is smaller than the growth in the total of EIP.TOU and load displacement NUG's impacts. As a result the January 20 Min Peak MW in those years is greater than the December 20 Min Peak MW. For years marked with **** the same holds for the 1-Hour Peak MW.

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1990													
20 Min PEAK MW	22363	21735	21285	19058	17768	19002	19369	19373	18016	18793	21036	22849	20054.0
1 hr PEAK MW	22116	21583	21087	18890	17618	18872	19251	19254	17848	18573	20824	22682	19883.2
Energy Gwh	12877	11646	12111	10427	10114	10313	10792	10720	10080	10751	11529	12636	133994.3
Energy Av MW	17308	17330	16278	14481	13594	14323	14506	14408	14000	14450	16013	16984	15296.2
*L.F. %	78.3	80.3	77.2	76.7	77.2	75.9	75.4	74.8	78.4	77.8	76.9	74.9	76.9
1991													
20 Min PEAK MW	23391	22159	21707	19181	17930	19047	19410	19435	18117	18981	21255	23125	20311.4
1 hr PEAK MW	23131	22005	21505	19011	17780	18920	19294	19320	17950	18759	21043	22958	20139.6
Energy Gwh	13301	11711	12150	10284	9996	10126	10589	10516	9891	10593	11367	12492	136104.2
Energy Av MW	17877	17428	16331	14283	13435	14064	14232	14135	13738	14238	15787	16791	15537.0
*L.F. %	76.6	78.4	75.1	74.2	74.6	73.4	72.8	72.2	75.4	74.7	73.9	72.1	77.1
1992													
20 Min PEAK MW	24259	22948	22473	19823	18563	19741	20182	20205	18819	19640	22037	24171	21071.8
1 hr PEAK MW	23985	22786	22260	19645	18406	19607	20059	20082	18642	19406	21813	23992	20890.3
Energy Gwh	14023	12828	12842	10909	10602	10763	11293	11222	10580	11300	12134	13416	141911.5
Energy Av MW	18847	18431	17261	15151	14250	14948	15179	15084	14694	15188	16853	18033	16155.7
*L.F. %	78.6	80.9	77.5	77.1	77.4	76.2	75.7	75.1	78.8	78.3	77.3	75.2	77.5
1993													
20 Min PEAK MW	24840	23504	22995	20253	18958	20143	20621	20634	19238	20047	22516	24728	21539.8
1 hr PEAK MW	24557	23338	22776	20070	18798	20007	20497	20510	19058	19807	22287	24546	21354.3
Energy Gwh	14398	12717	13163	11164	10838	10994	11545	11472	10804	11541	12407	13732	144775.6
Energy Av MW	19352	18924	17692	15505	14567	15270	15518	15420	15006	15513	17231	18457	16526.9
*L.F. %	78.8	81.1	77.7	77.3	77.5	76.3	75.7	75.2	78.7	78.3	77.3	75.2	77.4
1994													
20 Min PEAK MW	25350	23973	23446	20606	19306	20512	21012	21024	19590	20410	22964	25283	21956.4
1 hr PEAK MW	25060	23804	23221	20420	19142	20374	20886	20899	19406	20163	22730	25096	21766.8
Energy Gwh	14725	13006	13452	11392	11061	11223	11793	11719	11034	11791	12694	14079	147967.6
Energy Av MW	19792	19354	18080	15822	14867	15587	15851	15751	15325	15848	17630	18923	16891.3
*L.F. %	79.0	81.3	77.9	77.5	77.7	76.5	75.9	75.4	79.0	78.6	77.6	75.4	77.6

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1995													
20 Min PEAK MW	25957	24534	23985	21035	19725	20952	21470	21542	20005	20835	23484	26071	22466.2
1 hr PEAK MW	25658	24361	23751	20844	19556	20811	21342	21415	19816	20581	23243	25877	22271.2
Energy Gwh	15119	13353	13798	11669	11331	11495	12087	12006	11302	12078	13020	14559	151817.6
Energy Av MW	20321	19870	18544	16207	15230	15965	16245	16137	15698	16234	18084	19568	17330.8
*L.F. %	79.2	81.6	78.1	77.8	77.9	76.7	76.1	75.4	79.2	78.9	77.8	75.6	77.8
1996													
20 Min PEAK MW	26569	25110	24552	21516	20094	21365	21903	21981	20397	21333	24080	26764	22971.9
1 hr PEAK MW	26261	24931	24311	21319	19919	21220	21771	21849	20202	21071	23831	26563	22770.6
Energy Gwh	15478	14162	14125	11937	11592	11767	12376	12296	11577	12374	13353	14943	155980.0
Energy Av MW	20803	21075	18985	16579	15580	16343	16635	16527	16079	16632	18546	20085	17805.9
*L.F. %	79.2	84.5	78.1	77.8	78.2	77.0	76.4	75.6	79.6	78.9	77.8	75.6	78.2
1997 ****													
20 Min PEAK MW	27228	25691	25086	21929	20462	21746	22276	22332	20683	21598	24385	27104	23376.7
1 hr PEAK MW	26910	25506	24837	21726	20282	21596	22140	22198	20482	21329	24131	26899	23169.7
Energy Gwh	15875	14007	14449	12187	11827	11996	12606	12511	11764	12554	13544	15149	158470.0
Energy Av MW	21338	20843	19421	16926	15896	16662	16944	16816	16339	16874	18811	20362	18090.2
*L.F. %	79.3	81.7	78.2	77.9	78.4	77.2	76.5	75.8	79.8	79.1	78.0	75.7	78.1
1998 **													
20 Min PEAK MW	27504	25940	25327	22109	20641	21957	22501	22562	20881	21792	24644	27426	23607.0
1 hr PEAK MW	27180	25752	25073	21901	20457	21804	22363	22425	20676	21518	24384	27216	23395.8
Energy Gwh	16111	14215	14659	12353	11998	12175	12798	12703	11944	12738	13756	15396	160847.6
Energy Av MW	21655	21153	19704	17158	16126	16910	17202	17074	16589	17121	19106	20694	18361.6
*L.F. %	79.7	82.1	78.6	78.3	78.8	77.6	76.9	76.1	80.2	79.6	78.4	76.0	78.5
1999 ****													
20 Min PEAK MW	27909	26298	25661	22358	20876	22214	22763	22816	21091	21986	24888	27718	23881.6
1 hr PEAK MW	27577	26105	25401	22145	20688	22058	22621	22675	20882	21705	24622	27504	23665.3
Energy Gwh	16375	14439	14879	12521	12163	12343	12971	12870	12094	12883	13919	15582	163039.5
Energy Av MW	22009	21487	19998	17391	16349	17143	17434	17298	16797	17316	19332	20944	18611.8
*L.F. %	79.8	82.3	78.7	78.5	79.0	77.7	77.1	76.3	80.4	79.8	78.5	76.1	78.6

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2000 ****													
20 Min PEAK MW	28220	26578	25930	22561	21080	22448	23012	23068	21310	22197	25165	28059	24135.5
1 hr PEAK MW	27881	26381	25665	22344	20888	22289	22867	22925	21096	21910	24893	27840	23914.7
Energy Gwh	16624	14631	15100	12696	12341	12529	13170	13068	12279	13071	14134	15832	165476.6
Energy Av MW	22344	21773	20296	17634	16588	17402	17702	17564	17055	17569	19630	21280	18890.0
*L.F. %	80.1	82.5	79.1	78.9	79.4	78.1	77.4	76.6	80.8	80.2	78.9	76.4	79.0
2001 **													
20 Min PEAK MW	28590	26918	26262	22825	21359	22765	23348	23415	21625	22497	25534	28477	24469.7
1 hr PEAK MW	28244	26717	25991	22603	21163	22602	23200	23268	21407	22205	25257	28273	24244.3
Energy Gwh	16894	14895	15338	12886	12543	12739	13393	13289	12488	13273	14361	16094	168192.7
Energy Av MW	22707	22166	20615	17897	16859	17693	18001	17862	17344	17841	19946	21632	19200.1
*L.F. %	80.4	83.0	79.3	79.2	79.7	78.3	77.6	76.8	81.0	80.3	79.0	76.5	79.2
2002 **													
20 Min PEAK MW	29042	27338	26671	23164	21706	23143	23739	23808	21982	22839	25943	28971	24862.1
1 hr PEAK MW	28689	27133	26394	22938	21506	22976	23588	23658	21759	22540	25660	28742	24631.9
Energy Gwh	17184	15151	15599	13098	12760	12962	13628	13523	12707	13495	14608	16378	171092.2
Energy Av MW	23097	22546	20966	18192	17150	18002	18317	18176	17648	18139	20289	22013	19531.1
*L.F. %	80.5	83.1	79.4	79.3	79.7	78.4	77.7	76.8	81.1	80.5	79.1	76.6	79.3
2003 **													
20 Min PEAK MW	29528	27790	27111	23533	22071	23539	24148	24220	22355	23206	26377	29469	25278.8
1 hr PEAK MW	29167	27581	26828	23302	21867	23369	23994	24067	22128	22901	26087	29235	25043.7
Energy Gwh	17490	15420	15872	13323	12986	13193	13872	13765	12933	13727	14866	16671	174118.5
Energy Av MW	23508	22946	21333	18504	17455	18324	18645	18502	17962	18451	20648	22407	19876.5
*L.F. %	80.6	83.2	79.5	79.4	79.8	78.4	77.7	76.9	81.2	80.6	79.1	76.6	79.4
2004 **													
20 Min PEAK MW	30041	28269	27576	23926	22452	23950	24572	24645	22743	23595	26832	29989	25715.9
1 hr PEAK MW	29673	28055	27288	23690	22243	23777	24415	24489	22511	23283	26536	29751	25476.0
Energy Gwh	17807	15660	16157	13556	13219	13431	14123	14013	13165	13969	15133	16974	177206.9
Energy Av MW	23935	23304	21716	18828	17767	18654	18982	18835	18285	18775	21018	22815	20229.1
*L.F. %	80.7	83.1	79.6	79.5	79.9	78.5	77.7	76.9	81.2	80.6	79.2	76.7	79.4

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2005 **													
20 Min PEAK MW	30574	28766	28059	24335	22847	24377	25012	25088	23148	24003	27309	30532	26170.8
1 hr PEAK MW	30198	28547	27765	24094	22634	24200	24851	24928	22911	23685	27007	30289	25925.8
Energy Gwh	18135	15988	16452	13800	13460	13679	14385	14274	13410	14222	15412	17291	180508.4
Energy Av MW	24375	23792	22113	19166	18092	18999	19334	19186	18625	19116	21406	23240	20606.0
*L.F. %	80.7	83.3	79.6	79.5	79.9	78.5	77.8	77.0	81.3	80.7	79.3	76.7	79.5
2006 **													
20 Min PEAK MW	31128	29282	28561	24759	23252	24812	25461	25537	23557	24416	27787	31075	26635.7
1 hr PEAK MW	30744	29059	28261	24513	23035	24631	25297	25374	23315	24091	27480	30827	26385.7
Energy Gwh	18470	16282	16752	14046	13704	13927	14646	14533	13651	14474	15688	17603	183774.7
Energy Av MW	24825	24229	22516	19508	18420	19343	19685	19533	18960	19454	21789	23660	20978.9
*L.F. %	80.7	83.4	79.7	79.6	80.0	78.5	77.8	77.0	81.3	80.8	79.3	76.7	79.5
2007													
20 Min PEAK MW	31690	29813	29085	25211	23692	25291	25960	26043	24028	24900	28350	31716	27148.3
1 hr PEAK MW	31298	29586	28778	24960	23470	25107	25793	25878	23781	24568	28036	31463	26893.2
Energy Gwh	18826	16598	17079	14320	13978	14210	14948	14835	13938	14776	16022	17982	187512.2
Energy Av MW	25304	24700	22955	19889	18788	19736	20091	19939	19358	19861	22252	24170	21405.5
*L.F. %	80.8	83.5	79.8	79.7	80.1	78.6	77.9	77.0	81.4	80.8	79.4	76.8	79.6
2008 **													
20 Min PEAK MW	32338	30415	29665	25704	24160	25787	26464	26545	24484	25354	28867	32292	27672.9
1 hr PEAK MW	31938	30183	29352	25448	23934	25599	26293	26376	24232	25017	28547	32034	27412.7
Energy Gwh	19194	16873	17404	14587	14240	14475	15222	15105	14189	15034	16299	18291	190912.2
Energy Av MW	25798	25108	23392	20259	19140	20104	20460	20302	19707	20206	22638	24585	21793.6
*L.F. %	80.8	83.2	79.7	79.6	80.0	78.5	77.8	77.0	81.3	80.8	79.3	76.7	79.5
2009 **													
20 Min PEAK MW	32928	30971	30210	26175	24616	26278	26970	27056	24957	25836	29422	32919	28194.8
1 hr PEAK MW	32520	30734	29891	25914	24385	26086	26796	26884	24699	25492	29096	32656	27929.4
Energy Gwh	19559	17242	17737	14866	14520	14761	15525	15407	14473	15331	16625	18660	194707.1
Energy Av MW	26289	25658	23840	20648	19517	20501	20867	20708	20102	20606	23091	25081	22226.8
*L.F. %	80.8	83.5	79.8	79.7	80.0	78.6	77.9	77.0	81.4	80.8	79.4	76.8	79.6

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2010 **													
20 Min PEAK MW	33566	31566	30786	26668	25088	26780	27484	27568	25427	26308	29962	33524	28727.3
1 hr PEAK MW	33150	31325	30461	26402	24853	26585	27307	27393	25164	25957	29629	33256	28456.9
Energy Gwh	19932	17569	18071	15144	14794	15038	15815	15694	14741	15608	16926	18997	198329.0
Energy Av MW	26790	26145	24289	21033	19884	20886	21257	21093	20474	20979	23508	25534	22640.3
*L.F. %	80.8	83.5	79.7	79.7	80.0	78.6	77.8	77.0	81.4	80.8	79.3	76.8	79.6
2011 **													
20 Min PEAK MW	34188	32152	31360	27165	25567	27296	28017	28106	25923	26815	30545	34182	29276.3
1 hr PEAK MW	33763	31906	31029	26894	25327	27096	27836	27926	25655	26457	30205	33908	29000.2
Energy Gwh	20315	17909	18421	15437	15086	15337	16131	16008	15038	15920	17267	19382	202250.6
Energy Av MW	27305	26650	24759	21441	20277	21301	21681	21516	20886	21398	23982	26051	23088.0
*L.F. %	80.9	83.5	79.8	79.7	80.1	78.6	77.9	77.0	81.4	80.9	79.4	76.8	79.6
2012 **													
20 Min PEAK MW	34855	32776	31966	27684	26062	27823	28555	28643	26415	27310	31110	34814	29834.3
1 hr PEAK MW	34423	32525	31627	27407	25818	27619	28371	28460	26142	26945	30763	34535	29552.8
Energy Gwh	20705	18199	18770	15727	15372	15627	16435	16307	15318	16211	17581	19735	205986.7
Energy Av MW	27830	27082	25229	21843	20662	21704	22090	21918	21275	21789	24418	26525	23514.5
*L.F. %	80.8	83.3	79.8	79.7	80.0	78.6	77.9	77.0	81.4	80.9	79.4	76.8	79.6
2013													
20 Min PEAK MW	35313	33209	32393	28052	26424	28216	28965	29059	26801	27703	31568	35338	30253.4
1 hr PEAK MW	34874	32954	32049	27771	26176	28009	28778	28874	26524	27332	31217	35054	29967.7
Energy Gwh	21004	18516	19046	15958	15606	15866	16690	16564	15561	16465	17862	20054	209191.7
Energy Av MW	28231	27554	25600	22164	20976	22037	22433	22263	21612	22130	24808	26954	23880.3
*L.F. %	81.0	83.6	79.9	79.8	80.1	78.7	78.0	77.1	81.5	81.0	79.5	76.9	79.7
2014													
20 Min PEAK MW	35869	33732	32904	28492	26851	28675	29438	29535	27240	28148	32082	35919	30740.3
1 hr PEAK MW	35423	33473	32555	28206	26598	28464	29247	29346	26959	27771	31724	35630	30449.5
Energy Gwh	21347	18819	19358	16218	15866	16133	16970	16844	15824	16739	18163	20394	212674.8
Energy Av MW	28692	28005	26019	22525	21325	22406	22810	22639	21978	22499	25226	27411	24277.9
*L.F. %	81.0	83.7	79.9	79.9	80.2	78.7	78.0	77.1	81.5	81.0	79.5	76.9	79.7

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

2015 **	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
20 Min PEAK MW	36621	34426	33567	29053	27377	29225	29991	30078	27729	28631	32622	36513	31319.4
1 hr PEAK MW	36166	34162	33211	28761	27119	29010	29796	29886	27442	28247	32258	36219	31023.1
Energy Gwh	21749	19167	19707	16503	16141	16407	17254	17117	16075	16994	18432	20690	216237.1
Energy Av MW	29233	28522	26488	22921	21696	22788	23191	23007	22326	22841	25600	27810	24684.6
*L.F. %	80.8	83.5	79.8	79.7	80.0	78.6	77.8	77.0	81.4	80.9	79.4	76.8	79.6

* Load Factor based on 1-Hour Peak

NOTE

For years marked with ** the growth of Basic Load over the course of the year is smaller than the growth in the total of EIP.TOU and load displacement NUG's impacts. As a result the January 20 Min Peak MW in those years is greater than the December 20 Min Peak MW. For years marked with **** the same holds for the 1-Hour Peak MW.

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1990													
20 Min PEAK MW	1062	1062	1009	946	906	874	871	863	948	1007	1070	1124	978.5
1 hr PEAK MW	1058	1057	1006	939	900	870	867	859	944	1002	1066	1119	973.9
Energy Gwh	663	605	628	588	594	568	566	585	589	660	670	715	7430.3
Energy Av MW	891	900	844	816	798	789	761	787	817	887	931	961	848.2
*L.F. %	84.3	85.1	83.9	86.9	88.6	90.8	87.7	91.6	86.6	88.5	87.3	85.9	87.1
1991													
20 Min PEAK MW	1071	1070	1045	968	919	889	886	871	933	978	1041	1094	980.3
1 hr PEAK MW	1068	1065	1041	962	914	884	882	869	929	972	1038	1090	976.1
Energy Gwh	669	612	637	601	604	578	574	590	575	635	649	690	7413.1
Energy Av MW	900	911	856	834	811	803	772	793	798	854	901	927	846.2
*L.F. %	84.2	85.5	82.3	86.7	88.8	90.9	87.5	91.3	85.9	87.9	86.8	85.1	86.7
1992													
20 Min PEAK MW	1076	1075	1048	969	920	889	886	873	935	981	1044	1096	982.7
1 hr PEAK MW	1073	1070	1043	962	915	885	882	869	931	974	1040	1092	978.0
Energy Gwh	679	643	645	606	610	585	581	598	581	643	656	700	7526.1
Energy Av MW	913	923	867	842	820	812	781	804	807	864	911	940	856.8
*L.F. %	85.0	86.3	83.1	87.5	89.6	91.8	88.6	92.6	86.7	88.7	87.6	86.1	87.6
1993													
20 Min PEAK MW	1101	1097	1066	980	930	895	889	873	939	986	1051	1105	992.8
1 hr PEAK MW	1098	1091	1062	973	925	890	884	869	934	979	1047	1101	987.8
Energy Gwh	699	638	661	619	621	593	589	604	587	650	665	711	7637.3
Energy Av MW	940	949	889	859	834	824	792	812	816	874	923	956	871.8
*L.F. %	85.6	87.0	83.7	88.3	90.2	92.6	89.6	93.4	87.3	89.2	88.2	86.8	88.3
1994													
20 Min PEAK MW	1107	1102	1072	983	934	897	890	878	947	997	1065	1123	999.7
1 hr PEAK MW	1103	1096	1067	975	929	891	886	873	941	990	1061	1118	994.3
Energy Gwh	714	652	676	631	633	605	601	619	602	668	686	735	7821.6
Energy Av MW	959	970	908	877	851	840	808	831	837	898	952	988	892.9
*L.F. %	87.0	88.5	85.1	89.9	91.6	94.3	91.2	95.3	88.9	90.7	89.8	88.4	89.8

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1995													
20 Min PEAK MW	1106	1099	1069	975	925	884	878	864	940	993	1063	1127	993.5
1 hr PEAK MW	1103	1094	1065	967	919	878	874	860	935	985	1058	1122	988.3
Energy Gwh	726	662	685	638	640	611	607	624	609	678	696	752	7928.2
Energy Av MW	976	985	921	887	860	848	816	839	846	912	967	1010	905.0
*L.F. %	88.5	90.1	86.5	91.7	93.6	96.6	93.3	97.5	90.5	92.6	91.4	90.0	91.6
1996													
20 Min PEAK MW	1099	1091	1059	964	910	870	862	849	923	979	1050	1115	980.9
1 hr PEAK MW	1095	1086	1054	956	904	864	858	845	917	971	1046	1110	975.5
Energy Gwh	719	681	678	631	632	602	598	615	601	670	690	745	7861.3
Energy Av MW	966	1013	911	876	849	837	803	827	835	901	958	1001	897.4
*L.F. %	88.2	93.3	86.4	91.6	93.9	96.8	93.6	97.9	91.1	92.7	91.6	90.2	92.0
1997													
20 Min PEAK MW	1110	1103	1068	971	917	876	868	854	930	987	1060	1126	989.1
1 hr PEAK MW	1106	1097	1064	963	911	869	863	850	924	979	1055	1120	983.3
Energy Gwh	734	669	691	643	644	614	610	628	613	683	703	760	7990.8
Energy Av MW	986	996	928	893	866	853	820	844	851	918	976	1021	912.2
*L.F. %	89.2	90.8	87.2	92.7	95.0	98.1	95.0	99.3	92.1	93.7	92.5	91.1	92.8
1998													
20 Min PEAK MW	1118	1110	1076	977	923	881	873	858	936	993	1067	1136	995.6
1 hr PEAK MW	1114	1104	1071	968	916	874	868	854	930	985	1063	1130	989.7
Energy Gwh	746	680	702	653	655	625	620	639	623	694	715	774	8123.5
Energy Av MW	1003	1012	943	907	880	868	833	858	865	932	993	1040	927.3
*L.F. %	90.0	91.6	88.1	93.7	96.1	99.3	96.1	100.5	93.0	94.7	93.3	92.0	93.7
1999													
20 Min PEAK MW	1129	1122	1086	984	931	888	879	865	944	1000	1077	1147	1004.1
1 hr PEAK MW	1125	1116	1081	975	924	881	875	860	939	992	1072	1141	998.2
Energy Gwh	758	692	713	663	665	634	630	649	633	704	725	785	8252.5
Energy Av MW	1019	1030	959	920	894	881	847	872	879	946	1008	1055	942.1
*L.F. %	90.6	92.3	88.7	94.4	96.8	100.0	96.9	101.4	93.7	95.4	94.0	92.5	94.4

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2000													
20 Min PEAK MW	1135	1127	1092	989	935	892	883	869	950	1007	1085	1157	1010.1
1 hr PEAK MW	1132	1122	1087	980	929	885	879	864	944	998	1080	1151	1004.3
Energy Gwh	771	702	725	674	677	646	641	661	645	717	740	800	8378.4
Energy Av MW	1037	1045	975	936	910	898	862	888	896	964	1027	1075	958.7
*L.F. %	91.6	93.1	89.7	95.5	97.9	101.4	98.0	102.7	94.9	96.5	95.1	93.4	95.5
2001													
20 Min PEAK MW	1155	1149	1114	1008	958	914	907	893	978	1035	1117	1193	1035.1
1 hr PEAK MW	1151	1143	1108	999	951	906	902	888	972	1026	1112	1187	1028.8
Energy Gwh	789	721	743	691	696	664	660	680	664	739	763	826	8634.7
Energy Av MW	1060	1072	998	960	935	923	887	914	923	993	1059	1110	985.7
*L.F. %	92.1	93.8	90.1	96.1	98.3	101.8	98.4	102.9	95.0	96.8	95.2	93.5	95.8
2002													
20 Min PEAK MW	1187	1181	1145	1036	986	941	933	920	1008	1066	1151	1228	1065.3
1 hr PEAK MW	1183	1175	1140	1027	978	934	928	915	1001	1056	1145	1222	1058.8
Energy Gwh	811	741	765	711	717	685	680	701	685	761	785	851	8892.8
Energy Av MW	91.8	93.4	89.8	95.3	97.7	101.1	97.9	102.4	94.3	96.0	94.8	93.2	95.3
*L.F. %	92.2	93.9	90.2	96.1	98.5	101.8	98.5	103.0	95.0	96.9	95.3	93.6	95.9
2003													
20 Min PEAK MW	1224	1217	1180	1068	1018	972	964	950	1041	1100	1188	1269	1099.3
1 hr PEAK MW	1219	1211	1174	1058	1011	964	959	945	1035	1091	1183	1262	1092.7
Energy Gwh	837	765	789	734	740	707	702	724	708	786	812	880	9182.7
Energy Av MW	1126	1138	1060	1019	994	982	944	973	983	1056	1128	1182	1048.3
*L.F. %	92.4	94.0	90.3	96.3	98.4	101.8	98.4	102.9	95.0	96.8	95.3	93.7	95.9
2004													
20 Min PEAK MW	1259	1252	1214	1099	1048	1000	992	978	1072	1131	1222	1305	1130.9
1 hr PEAK MW	1254	1245	1209	1089	1040	992	987	973	1065	1121	1216	1298	1124.0
Energy Gwh	863	787	813	756	763	729	724	747	730	810	836	906	9462.8
Energy Av MW	1160	1171	1092	1050	1026	1012	973	1003	1013	1088	1161	1218	1080.2
*L.F. %	92.6	94.1	90.4	96.4	98.7	102.0	98.6	103.2	95.2	97.0	95.5	93.8	96.1

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2005													
20 Min PEAK MW	1304	1297	1258	1139	1086	1037	1029	1014	1111	1173	1266	1352	1172.1
1 hr PEAK MW	1299	1290	1252	1128	1078	1029	1023	1009	1104	1162	1261	1345	1165.0
Energy Gwh	891	813	839	780	788	752	747	770	752	835	863	935	9766.1
Energy Av MW	1198	1210	1128	1083	1059	1044	1004	1035	1045	1123	1199	1257	1114.9
*L.F. %	92.2	93.8	90.1	96.0	98.2	101.5	98.1	102.6	94.6	96.7	95.1	93.4	95.7
2006													
20 Min PEAK MW	1348	1340	1300	1176	1123	1072	1063	1048	1148	1211	1307	1396	1211.1
1 hr PEAK MW	1343	1333	1294	1166	1114	1064	1057	1042	1141	1200	1301	1389	1203.7
Energy Gwh	918	839	864	804	812	775	770	793	776	860	888	963	10062.3
Energy Av MW	1234	1248	1162	1117	1091	1077	1034	1066	1077	1156	1234	1294	1148.7
*L.F. %	91.9	93.6	89.8	95.7	98.0	101.2	97.8	102.3	94.4	96.4	94.8	93.2	95.4
2007													
20 Min PEAK MW	1390	1383	1341	1214	1160	1107	1099	1083	1186	1250	1350	1441	1250.2
1 hr PEAK MW	1385	1376	1335	1203	1152	1098	1093	1077	1179	1239	1343	1434	1242.7
Energy Gwh	946	865	891	829	837	799	794	818	800	887	917	993	10375.8
Energy Av MW	1272	1287	1198	1151	1126	1110	1067	1099	1111	1192	1273	1335	1184.5
*L.F. %	91.8	93.5	89.7	95.7	97.8	101.0	97.6	102.1	94.2	96.2	94.8	93.1	95.3
2008													
20 Min PEAK MW	1430	1422	1378	1248	1192	1138	1130	1113	1218	1283	1386	1479	1284.8
1 hr PEAK MW	1425	1414	1372	1237	1184	1130	1123	1106	1211	1272	1379	1471	1277.0
Energy Gwh	974	887	918	853	862	823	817	842	823	912	942	1020	10672.7
Energy Av MW	1310	1320	1234	1185	1158	1142	1098	1132	1143	1225	1308	1371	1218.3
*L.F. %	91.9	93.4	89.9	95.8	97.8	101.1	97.8	102.3	94.4	96.3	94.9	93.2	95.4
2009													
20 Min PEAK MW	1478	1471	1426	1292	1236	1181	1171	1155	1264	1331	1437	1534	1331.3
1 hr PEAK MW	1473	1463	1419	1281	1227	1172	1164	1148	1256	1320	1430	1526	1323.2
Energy Gwh	1005	918	946	880	889	850	844	870	850	942	973	1054	11020.4
Energy Av MW	1351	1366	1272	1222	1195	1180	1134	1169	1181	1266	1352	1416	1258.0
*L.F. %	91.7	93.3	89.6	95.4	97.4	100.7	97.4	101.8	94.0	96.0	94.5	92.8	95.1

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2010													
20 Min PEAK MW	1528	1520	1474	1336	1278	1221	1212	1195	1308	1375	1485	1584	1376.3
1 hr PEAK MW	1523	1512	1468	1324	1268	1211	1205	1188	1299	1363	1478	1576	1367.9
Energy Gwh	1037	946	976	908	918	876	871	898	876	972	1003	1087	11368.4
Energy Av MW	1393	1408	1312	1261	1234	1217	1170	1207	1217	1306	1393	1462	1297.8
*L.F. %	91.5	93.1	89.4	95.2	97.3	100.4	97.1	101.6	93.7	95.8	94.3	92.7	94.9
2011													
20 Min PEAK MW	1576	1569	1521	1379	1319	1261	1251	1234	1349	1420	1531	1634	1420.3
1 hr PEAK MW	1571	1561	1514	1367	1310	1251	1245	1227	1341	1407	1524	1626	1412.0
Energy Gwh	1067	976	1006	935	946	903	896	924	903	1001	1033	1119	11709.5
Energy Av MW	1435	1452	1352	1299	1271	1253	1205	1242	1254	1345	1435	1505	1336.7
*L.F. %	91.3	93.0	89.3	95.0	97.0	100.2	96.8	101.3	93.5	95.6	94.1	92.5	94.7
2012													
20 Min PEAK MW	1621	1613	1564	1419	1358	1298	1287	1269	1388	1459	1574	1679	1460.8
1 hr PEAK MW	1615	1604	1557	1406	1348	1288	1280	1262	1380	1447	1567	1671	1452.1
Energy Gwh	1100	1003	1037	964	975	931	924	953	931	1031	1065	1153	12067.1
Energy Av MW	1479	1492	1393	1339	1310	1293	1242	1281	1293	1386	1479	1550	1377.5
*L.F. %	91.6	93.0	89.5	95.3	97.2	100.4	97.0	101.5	93.7	95.8	94.3	92.7	94.9
2013													
20 Min PEAK MW	1676	1668	1617	1466	1405	1341	1331	1312	1435	1507	1625	1734	1509.8
1 hr PEAK MW	1670	1659	1610	1453	1394	1331	1324	1305	1426	1494	1618	1725	1500.8
Energy Gwh	1132	1034	1066	991	1002	956	950	979	957	1058	1093	1183	12400.9
Energy Av MW	1522	1538	1432	1376	1347	1328	1277	1316	1329	1423	1518	1590	1415.6
*L.F. %	91.1	92.7	88.9	94.7	96.7	99.8	96.4	100.8	93.2	95.2	93.8	92.2	94.3
2014													
20 Min PEAK MW	1725	1716	1665	1510	1446	1382	1372	1352	1477	1552	1673	1785	1554.6
1 hr PEAK MW	1719	1707	1657	1497	1435	1372	1364	1344	1468	1539	1666	1776	1545.4
Energy Gwh	1164	1063	1096	1020	1031	985	978	1008	984	1090	1125	1217	12760.2
Energy Av MW	1564	1581	1473	1416	1386	1367	1315	1355	1367	1465	1562	1636	1456.6
*L.F. %	91.0	92.6	88.9	94.6	96.6	99.7	96.4	100.8	93.1	95.2	93.7	92.1	94.3

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 901210

2015	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
20 Min PEAK MW	1775	1766	1712	1554	1489	1423	1412	1392	1521	1597	1722	1836	1600.0
1 hr PEAK MW	1769	1757	1705	1540	1478	1412	1404	1384	1512	1583	1714	1827	1590.5
Energy Gwh	1197	1093	1127	1048	1060	1012	1005	1035	1012	1119	1156	1250	13113.2
Energy Av MW	1608	1626	1515	1455	1425	1406	1350	1392	1405	1504	1605	1681	1496.9
*L.F. %	90.9	92.6	88.8	94.5	96.4	99.6	96.1	100.5	92.9	95.0	93.6	92.0	94.1

* Load Factor based on 1-Hour Peak

NOTE

For years marked with ** the growth of Basic Load over the course of the year is smaller than the growth in the total of EIP.TOU and load displacement NUG's impacts. As a result the January 20 Min Peak MW in those years is greater than the December 20 Min Peak MW. For years marked with **** the same holds for the 1-Hour Peak MW.

7.0 UNCERTAINTY IN THE LOAD FORECAST

7.1 Introduction

The methodology used to estimate the uncertainty band around the 1990 Load Forecast was developed in 1988 and modified slightly in 1989 (see 'Uncertainty in the Load Forecast, A Summary of Results Developed in 1988 and 1989': December, 1989). The approach taken in 1990 is identical to that used in 1989, but for dropping the constant term in the energy equation. The uncertainty in the load forecast is derived in a two-stage process. First the uncertainty associated with economic growth in Ontario is estimated and then the uncertainty associated with future trends in electricity consumption is determined taking into account GDP uncertainty. This is done via a stochastic simulation procedure which generates the probability distributions of these two dimensions of uncertainty using two empirically constructed Variable Elasticity Models - for load growth and economic growth.

7.2 The Estimated Equations

The economic growth model and the energy model were updated with 1989 data and re-estimated. The estimated equations are as follows:

i) Economic Growth Model

$$\log (GDP_t)) = \underset{(24.1)}{0.583} * \log (POP_t) + \underset{(29.3)}{0.0088} * [\log(POP_t)]^3 + e_t$$

Estimation Period: 1962 - 1989
Adjusted R-Squared: 0.991

ii) Energy Model

$$\log(ENERGY_t) = \underset{(284.0)}{3.05} * \log(GDP_t) - \underset{(82.7)}{0.22} * [\log(GDP_t)]^2 + e_t$$

Estimation Period: 1947 - 1989
Adjusted R-Squared: 0.998
Standard Error of Equation at Mean = 198 average megawatts

7.3 Estimated 80% Confidence Interval for Annual System Energy

The probability distribution for the 1990 Load Forecast was again produced using the stochastic simulation approach.

This procedure was carried out as follows: First, standard Monte Carlo simulation methods were used to draw 500 samples from the assumed distribution of Ontario population growth rates for every year of the forecast period. Then, using this data, the economic growth model was simulated yielding 500 samples of GDP for each forecast year. Finally, the energy model was simulated giving 500 samples of Ontario Hydro energy for each year. These simulated samples were then used to produce distributions for population, GDP and load.

The 80% confidence interval for system energy is reproduced in section 1 on Table 1.8. The results have been adjusted, from those produced by the actual simulation, so that the median corresponds to the official forecast. The required adjustments are shown in the table below.

Required Adjustment

Year	TW.h	Percent
Short-Term		
1990	-0.55	-0.39
1991	-0.04	-0.03
1992	1.11	0.74
1993	0.10	0.06
1994	0.63	0.39
1995	0.55	0.34
Long-Term		
2000	-0.31	-0.16
2005	-1.13	-0.54
2010	0.80	0.35
2015	2.63	1.06

7.4 Changes from 1989 Load Forecast

As reported in the 1989 Load Forecast Report[2], the total stochastic simulation of the variable elasticity energy model produced an unacceptable wide bandwidth in the early years of the forecast period due to the fact that the coefficient and residual error uncertainty do not change over time. During 1990, therefore, an attempt was made to reduce this constant component of total uncertainty while, at the same time, maintaining the integrity of the model.

The approach adopted was to estimate the energy equation without an intercept term. Since the energy model has only GDP as an explanatory variable this was a relatively simple exercise involving experimentation to find the appropriate scaling factor for GDP such that the constant term became statistically insignificant. The intercept was then excluded and the equation re-estimated.

As reported in section 1.8 investigations are continuing into the appropriate methodologies for use in deriving probability distributions for the Basic Peak Load Forecasat and for the Primary Load Forecast. At the present time the distribution for the Basic Peak Load Forecast has been derived using a constant load factor applied to the Basic Energy forecast. Analysis of the uncertainty in the Primary Load Forecast has been done by simulating a range of assumptions about the economic potential and penetration rate of demand - side management programs. These studies indicate that over a broad range of assumptions the bandwidth around the primary forecast should be very similar to that around the basic forecast.[3]

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[2] Load Forecast Report No. 891211 (p.109) Load Forecasts Department, Economics and Forecasts Division.

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[3] Complete peak and primary probability distributions are available on request.

8.0 GLOSSARY

8.1 Demand (Versus Load)

Demand means the electrical output from the Corporation's generating resources together with outside purchases required to supply the load of the Corporation's customers. In this report demand refers to the level of demand at the generating stations, while load refers to the flow of electricity at the wholesale billing points. Each term refers to peak or energy as specified in context.

Power means an instantaneous time rate of delivery of energy. Peak refers to the power averaged over a short period during which time the load is at its maximum. Energy demand is the accumulation of power over time, which results in an amount of useful work (or heat, lighting etc.)

In this report energy is reported in units of terawatt-hours or else in average megawatts. To obtain average megawatts for a period of time, the megawatt-hour figure is divided by the number of hours in the period.

Annual and Winter Peak Demand

All peak demands shown in this report incorporate the effects of typical weather conditions associated with the monthly peak demands. Under these conditions the annual peak demand occurs in December and the winter peak normally occurs in January.

Primary Peak Demand

Primary Peak Demand is the total generated and purchased minus secondary sales.

Secondary Sales:

Secondary Sales are of two types:: Ontario At-Will and Export.

Ontario At-Will:

These sales are at-will energy displacement sales from available resources in Ontario which are interruptible to supply the Primary contractual committments. These displace alternative energy sources on a fully interruptible, and at-will basis.

Export:

Electricity sales outside Ontario from available resources which are interruptible to supply the Primary Contract committments. Firm Export Sales are 'firm' relative to other Secondary Sales, but are Interruptible as necessary to meet the Primary Contract commitment.

Primary Demand in Terms of Generation

Primary Peak Demand is the sum of the customers' peak requirements (not necessarily coincident with the system peak) adjusted by an allowance for diversity and losses. This figure gives the primary peak demand at the level of the generating stations.

- **Peak** - The figures shown are those for the time of the maximum 1-hour or 20-minute peak demand.

An allowance for the weather effect expected on the typical monthly peak day is incorporated into the Primary Peak Demand for each month. Diversity and losses are affected by extreme weather as well.

- **Energy** - Monthly energy demands shown in this report are expressed in terawatt hours and average megawatts, in order to give an immediate impression of load factor, and also to make successive monthly values independent of differences arising solely from the varying lengths of the months.

Ontario Primary Demands in Terms of Generation

East System

Includes:

The primary power and energy loads of Municipalities, Industrial Customers, and Retail Customers in Ontario within the geographic boundaries of the Central, Western, Eastern, Georgian Bay and Northeastern Regions, together with appropriate diversity and losses.

Power and energy delivered free of charge by Ontario Hydro to Spruce Falls Power and Paper Company Limited in compensation for the effects of Little Long Generating Station on the Company's Smoky Falls Generating Station.

Excludes:

Power and energy exported to the United States and the Province of Quebec. Also excluded are deliveries under exchange agreements, namely, to Fort Erie on behalf of the CNP Company, and to Cornwall on behalf of the St. Lawrence Power Company. In both of these cases the amount of power delivered is made up at another point on the system so that there is no resultant demand on the Corporation's resources.

The loads of retail customers in Hornepayne, although customers of the Northeastern Region, because they are supplied from power resources within the Northwestern Region.

West System

Includes:

The primary power and energy loads of Municipalities, Direct and Retail Customers in Ontario within the geographic boundaries of the Northwestern Region, and the loads of retail customers in Hornepayne together with appropriate diversity and losses. The latter customers are included because they are supplied from resources within the Northwestern Region.

Power and energy delivered free of charge to Boise Cascade Company (Kenora), as compensation for the effects of Whitedog Falls Generating Station on the output of its generating stations.

Excludes:

Power and energy exported by Ontario Hydro to the United States and the Province of Manitoba.

Power and energy delivered to Boise Cascade at Fort Frances in exchange for the output of the Company's Calm Lake and Sturgeon Falls Generating Stations.

Ontario primary demands (both East and West Systems) exclude the delivery of turbo replacement power to various paper companies.

8.1.1 Basic Load Forecast

The Basic Load Forecast shows what would happen to electricity demand if Ontario Hydro did not adopt new activities to affect electricity demand. However, the current Demand/Supply Plan Study indicates that some future electricity needs of the province will be met by other means than by increasing supply. Ontario Hydro has programs to promote changes in the pattern of usage to allow some of the province's future electricity needs to be met by demand reductions.

8.1.2 Primary Load Forecast

The Primary Load Forecast takes into account the effect on Ontario Hydro demand of future Ontario Hydro activities designed to affect the level and shape of the load. It is derived by subtracting from the Basic Load Forecast the net effect of Load Displacement generation and Ontario Hydro's incentive-driven demand management programs which include:

(1) changes in rate structure such as time-of-use, off-peak incentives, etc;

(2) financial incentives such as grants or loans, etc.

It is the Primary Load Forecast which is to be used for supply planning purposes.

8.2 Diversity and Losses

Diversity is the difference between the sum of (individually metered) customer loads at the time of system peak and the arithmetic sum of the peak loads of all the customers regardless of whether they coincide with the system peak or not. Since individual customers experience their peak loads at diverse times, the arithmetic sum of their peak loads will be greater than the sum of customer loads at the time of system peak, and therefore the value for diversity is always negative.

Losses are the sum of electrical losses and consumption incurred in transmitting the electricity from the generating stations' terminals to all the customer metering points. This is evaluated by taking the difference between customer loads and system demands measured at the generating stations.

The figure for diversity and losses together will be positive if losses exceed diversity, and negative when diversity exceeds losses.

Diversity is a function of the timing of end-use utilization which is affected by social patterns and weather conditions. Losses are due mainly to transmission line loadings determined by system configuration and operation. System operation depends on hydraulic generation resources, export and circulating power flow, outages, etc.

There is no diversity in energy demand. The difference between the primary energy and the energy delivered to customers is losses.

8.3 Customers' Loads

Customers' Loads are the maximum peak loads of system customers which include cost contract municipalities, industrial customers and retail customers. Estimates of these loads are provided by the Regional Marketing Managers. The totals of these non-coincident customers' loads are referred to as the sums of customers' loads with appropriate qualifications for regional and other classifications.

The forecasts of Area loads in this report conform to the Power Billing Department, Customer Service Division practice of obtaining Area loads by summing the non-coincident loads of the D.S.'s supplying it.

8.3.1 Firm Loads

Firm Loads are supplied as required by the customer at all times as far as physical conditions permit.

8.3.2 Capacity Interruptible Loads

In general, capacity interruptible loads are those which can be interrupted under contract provisions which exchange interruptibility for the lower rates. Capacity interruptible power is the only class available. This class of power is available only for loads which can be reduced by at least 5,000 KW during interruption periods.

The sum of interruption periods shall not exceed the following:

(1) In any month up to 15% of the total time in the month.

(2) In any year up to 10% of the total time in the year.

(3) In any 5 consecutive years up to 5% of the total time in the 5 year period.

The purpose of supplying this class of power is to enable Ontario Hydro to reduce the generation reserves it would otherwise provide for, and to serve as a means of system relief under emergency conditions and other unpredictable circumstances.

Interruption Periods - (applicable Monday to Friday inclusive)

March to November inclusive - up to 5 hours per day
December, January and February - up to 14 hours per day

The customers' loads in this report are composed of the total firm and capacity interruptible. Therefore, in this report, the demands shown assume that rights of interruption under Capacity contracts are not exercised.

The amounts of power under contract within this class can therefore be regarded as being served out of reserve capacity planned for other purposes. No capacity is planned to meet interruptible loads.

8.4 Standby Power

The Corporation has undertaken to supply standby power to the following customers who have their own generation.

Table 8.4: Standby Amount

Boise Cascade - Kenora	10.5 MW
Boise Cascade - Fort Frances	8.0 MW
Eddy Forest Industries Ltd	7.5 MW
Gananoque Electric Light & Water	1.25 MW
Canadian Pacific Forest-Dryden (44 kV)	6.0 MW
Canadian Pacific Forest-Thunder Bay	17.1 MW
MacMillan Bloedel	1.8 MW

No specific allowance has been made for increases in the customers' load or system demands from standby requirements of customers.

Appendix 1

Weather Correction of Monthly Electricity Consumption Data

Purpose

The purpose of the weather correction to historical data is to remove variance considered to be noise by the forecaster. The electricity consumption forecast is made on the assumption of ordinary seasonal weather. Short term weather fluctuations affect the consumption of electricity by an amount which cannot be forecasted for the future beyond a few days, and therefore will not be incorporated in a monthly electricity consumption forecast. These fluctuations result in variation of typically up to 440 average MW on a monthly basis.

In the estimation of a model to be used for forecasting, the variance due to fluctuations of weather is noise which increases the error of estimation in the coefficients and can lead to an incorrect choice of model from the many under consideration. The prediction error of any chosen model is also increased by this noise since the weather influence is uncorrelated with the explanatory variables used in the model.

Definitions

Weather corrected energy is that energy use which would have been expected to occur during the period had the average weather effect been equal to its long term average value.

Weather corrected peak is that peak which would have been expected to occur during the period had the variability of the weather effect been equal to its long-term value.

Method

The method to correct actual recorded electricity consumption for the influence of weather is first to determine the amount by which the actual weather measures have deviated from the ordinarily expected amounts and second to calculate the electricity consumption deviation due to the weather deviations, taking into account the expected fluctuations of weather over the time period under consideration.

To do this a thirty year data base of all weather measures is maintained from the records made for Pearson International Airport. This is used as the source of the long run expected weather.

The correction system uses average daily values of the weather measures. Estimation of piece-wise linear models for days classified into different sub-populations by cooling or heating type is carried out, correcting for holidays, cycles and other such known effects. Once this is done, coefficients for the electricity consumption versus weather measure are available for correction of actual consumption by the weather effect experienced that day.

Estimation of the correction model coefficients for the seventeen years of history to be used in the estimation of monthly models by the Forecast Master system was done in four year blocks, rolling year to year. Correction figures for each year's months were obtained from the midpoint of the current four year model or the end, as appropriate.

The weather variables incorporated are as follows:

Heating Season

Temperature (average of 24 hours)	today	T
" " " "	yesterday	T24
" " " "	day before yesterday	T48
Illumination (by insolation meter)	today	I
Wind Speed	today	W

Cooling Season

Temperature	today	T
	yesterday	T24
Humidity (dew point depression)	today	H

APPENDIX 2.1

ANNUAL SHORT-TERM LOAD FORECASTING MODELS - MAY 1990

Error-Correction Model:

Assumptions: The assumption of Constant Return to Scale (CRS) with respect to GDP was imposed - statistically this assumption cannot be rejected.

Model:

$$\mathrm{Ln}(\mathrm{Av.\ MW}_{(t)}) = C_1 + C_2 * \mathrm{Ln}(\mathrm{GDP}_{(t)}) + C_3 * \mathrm{Ln}(\mathrm{GDP}_{(t-1)}) - (1-C_2-C_3) * \mathrm{Ln}(\mathrm{Av.\ MW}_{(t-1)})$$

$$+ C_5 * \mathrm{Ln}(\mathrm{PELEC}_{(t)}) + C_5 * \mathrm{Ln}(\mathrm{HDD}_{(t)}) + C_7 * \mathrm{Ln}(\mathrm{CDD}_{(t)})$$

The estimated results of this model are as follows:

	Parameter	T-Statistic	Standard Error
C_1	-1.0114	-2.1	.4786
C_2	0.5056	5.8	.0872
C_3	-0.4323	-4.0	.1079
$C_4 = (1-C_2-C_3)$	0.9257		
C_5	-0.0392	-2.0	.0201
C_6	0.1100	2.2	.0499
C_7	0.0244	2.1	.0118

Sample Period - 1963-1989

R-Squared = .999
Adjst. R-Squared = .999
S.E. of Regression = .011
D-W Statistics = 2.47
Log Likelihood = 87.64

Mean of Dependent Var = 9.1273
S.D. of Dependent Var = .3800
Sum of Squared Resid = .0024
F-Statistics = 6576.5

Standard Error of Regression at Mean of Dependent Variable = 97.8 Av. MW

Elasticities	Short-Run	Long-Run
Price of Electricity	-0.039	-0.54
Gross Domestic Product	0.506	1

Partial Adjustment Model

The model was estimated in a log linear form, and the additive time trend was excluded.

Model:

$$AV.\ MW_{(t)} = C_1 * PELECR_{(t)}^{C2} * PGAS_{(t)}^{C3} * GDP_{(t)}^{C4} * AV.\ MW_{(t-1)}^{C5} * HDD_{(t)}^{C6} * CDD_{(t)}^{C7}$$

The estimated results are as follows:

	Parameter	T-Statistic	Standard Error
C_1	-3.9728	-5.4	0.7334
C_2	-0.1785	-3.3	0.0534
C_3	0.0860	2.7	0.0324
C_4	0.4997	6.6	0.0758
C_5	0.6054	11.5	0.0527
C_6	0.0415	0.8	0.0528
C_7	0.0215	1.7	0.0124

Sample Period - 1963-1989

R-Square	= .999	Mean of Dependent Var	= 9.1273
Adjst. R-Square	= .999	S.D. of Dependent Var	= 0.3800
D-W Statistics	= 1.99	Sum of Squared Resid	= 0.0022
Log likelihood	= 88.85	F-Statistics	= 5711.4

Standard Error of Regression at Mean of Dependent Variable = 95.8 AV. MW

Elasticities	Short-Run	Long-Run
Price of Electricity	-0.179	-0.45
Price of Natural Gas	0.086	0.23
Gross Domestic Product	0.500	1.27

Table A2.1: Comparison of Model Forecasts and Customer Survey Results 1990 Short-Term Forecast

Total Primary Energy in Average MW

		Monthly Models State - Space		Annual Models			
Year	1989 Fcst LF891211	Primary	Basic	Error Correction	Partial Adjustment	Customer Survey	Recommended Basic
1990	16414	16068	16140	16390	16432	16650	16250
	2.8%*	0.7%	1.1%*	2.7%	3.1%	4.2%	1.8%
	2.0%**	0.0%	0.4%**	2.0%	2.4%	3.5%	1.1%
1991	16947	16342	16463	16788	16768	17492	16575
	3.3%	1.7%	2.0%	2.4%	1.9%	5.1%	2.0%
1992	17591	16637	16816	17321	17189	18233	17321
	3.8%	1.8%	2.2%	3.2%	2.5%	4.2%	4.5%
1993	18137			17822	17693	18932	17822
	3.1%			2.9%	2.9%	3.8%	2.9%
1994	18648			18309	18339	19739	18309
	2.8%			2.7%	3.7%	4.3%	2.7%
1995	19133			18856	19131	20689	18856
	2.6%			3.0%	4.3%	4.8%	3.0%

* Weather-Corrected
** Actual
See Table 2.2.1(A) and Table 2.2.1(B)

Appendix 2.2

Monthly Models

The Load Forecast Department's monthly models have been prepared using software, called Forecast Master, developed under contract to the Electric Power Research Institute. Ontario Hydro served as a test utility for this package during its original development and also tested the latest version called Forecast Master Plus. Two of the more sophisticated model options in the package have been utilized here: State-Space and Box-Jenkins. Hydro's results with the relevant models are presented below.

The State-Space model is the most comprehensive in its use of pertinent information and generally shows the best performance in terms of ex-post tests. It is Hydro's preferred methodology for monthly forecasting. The Box Jenkins model uses only the history of the data series to be forecast, hence its forecast shows a reliable continuation of current trends, and it is therefore valuable as a reference check against other results.

State-Space Model

A linear State-Space model of a time series consists of two equations. The first, called the state transition equation, is an updating function for the state vector which consists of all the information from the past relevant to forecasting the future. The second equation is the prediction equation which forecasts for each period based on the updated information set from the first equation and the history of the system to date.

The State-Space methodology relies on the analyst to specify the input variables on the basis of economic theory. Model diagnostics may be used to assess the appropriateness of the specification postulated in relation to other State-Space models. The State-Space model preferred this year has seasonally adjusted, real provincial GDP and an index of the real value of residential building permits as input variables.

The State-Space model is not a structural model, in the sense that the parameters estimated represent an observable quantity, but it is a well-accepted methodology and has been verified to be useful by both academics and practitioners in forecasting. In ex-post tests, this model proved to be the best of the several methods available. It responds to the most recent trends in the data (over the final years of history) and adapts to the seasonal patterns.

Compared to 1989, there are few changes in the formulation of the State-Space model:

- The monthly provincial GDP series provided by Economic Forecasts is seasonally differenced once to remove seasonality. Now both the weather corrected total system energy (WCTSE), and the residential building permits index and the monthly provincial GDP series are log-transformed, differenced once, and seasonally differenced once.

- The order of the model (corresponds to the dimension of the matrix of coefficients of the updating equations) is one less than 1989.

A summary of the estimation results for the State-Space model follows.

```
FORECAST MASTER PLUS Version 1.01 Mon. Jul 16 16:03:37 1990

STATE SPACE MODEL FOR WCTSEB2

Number of observations:  209            Complexity:  5.00
Mean of Log(WCTSEB2):  9.383102         Standard deviation:  0.193566
Standard forecast error:  0.013668      RMS error:  0.013470
Adjusted R-square: 0.995014             R-square (corrected for mean):  0.995134
Durbin-Watson statistic  2.115757       Ljung-Box:  (Chisq(18)=74.17 (1.000) **
Akaike criterion (AIC):  164.765344     Schwarz criterion (BIC):  172.862830

Variable             PCW D S            Coefficient

WCTSEB2              LOG 1 1            Endogenous

Seasonal SS parameters:
  A[1]                          0.0656762
  K[1]                         -0.599683

Short memory SS parameters:
  A[1]                          0.348348
  K[1]                         -0.329596
GDPONT7       LOG 1 1       Exogenous
  G[1][1]                       0.14718
BPERMIT9[-6]  LOG 1 1       Exogenous
G[1][2]                         0.00653894

No  constant
```

Box-Jenkins Model

This methodology uses only the patterns contained in the data history to prepare a forecast. No assumptions about cause and effect are made and no economic theory is used in this model; only the variable to be forecast is included in the data used for modelling. Once the model is estimated based on all the significant inter-temporal correlations in the recorded history, the most recent data is used to start the replication process which produces forecasts for the future.

The data series is log transformed, first simple differenced and first seasonal differences, and then the remaining time series is modelled. The optimal functional form is determined to be moving average in the first and twelve-period on the remaining series.

BOX-JENKINS MODEL FOR WCTSEB2

```
Number of observations:  221.        Complexity:  2.00
Mean of Log(WCTSEB2):  9.364083      Standard deviation:  0.205355
Standard forecast error:  0.013773   RMS error:  0.013710
Adjusted R-square:  0.995502         R-square (corrected for mean):  0.995522
Durbin-Watson statistic:  1.954324   Ljung-Box:  Chieq(18)=46.35 (1.000) **
Akaike criterion (AIC):  161.340433  Schwarz criterion (BIC):  163.840423

Variable         PCW D S    Coefficient    Std. Error   T-statistic     Prob.

WCTSEB2          LOG 1 1    Endogenous

b[1]                           0.37872     0.0856445         4.422      1.000
B[12]                          0.623727    0.0548936        11.362      1.000
No constant
```